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Decision 01-04-006 April 3, 2001

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking into the operation of interruptible load programs offered by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and the effect of these programs on energy prices, other demand responsiveness programs, and the reliability of the electric system. | Rulemaking 00-10-002<br>(Filed October 5, 2000) |

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# INTERIM OPINION

## 1. Summary

This decision adopts important improvements to the interruptible tariffs and rotating outage programs of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). These changes will improve the reliability of California's electric system for the near term, particularly Summer 2001.

The adopted programs are described in Attachment A. These programs largely implement the February 9, 2001 recommendations of the Energy Division, which we clarify and modify based on reasonable proposals and suggestions made in the February 14, 2001 Joint Proposal, the February 22, 2001 comments, and the February 26, 2001 reply comments.

This order provides a broad range of short-term and mid-term tools to help California get through the challenges of the immediate future, while additional steps are taken elsewhere to implement a more comprehensive response to the situations that Californians now face.

## 2. Interruptible Tariffs Background

### 2.1 Description of Utility Programs

PG&E, SCE and SDG&E have operated interruptible programs since the mid-1980's. These programs generally operate by paying customers to reduce their electricity use during times when demand is high. Customers willing to interrupt their use, or be interrupted by the utility, are compensated for participation through fixed payments (i.e., dollars per month), a discount off their electricity rate, or on a pay-per-event basis.

Interruptible programs are not inexpensive, however, and in some cases can cost the same or more than the prices currently charged for energy in today's dysfunctional wholesale market.[1] For example, a customer on PG&E's interruptible program, even if curtailed for the maximum limit of 100 hours, receives $0.84/kWh. If curtailed for only 10 hours, the price is $8.40/kWh. A customer on SCE's system curtailed for the program limit of 150 hours would receive between $0.50/kWh and $0.80 per kWh, with higher prices for less hours of interruption. Current interruptible programs cost about $220 million per year for about 2,200 megawatts (MW) of available interruptible load.

Respondent utilities currently operate three types of interruptible programs: traditional, air conditioner cycling plus agricultural pumping, and demand responsive.

#### 2.1.1 Traditional

Traditional interruptible tariffs are targeted toward industrial and large commercial customers. Traditional programs require that the customer have a meter that records usage over time (to verify compliance), advanced telecommunications equipment (to notify of interruptions), and large loads (to be cost-effective).

Participating customers receive a discount off of their electricity rates of about 15%. In exchange, they agree to interrupt service 80 to 150 hours per year (depending upon the serving utility). Customers have 30 minutes to reduce load once notified. Customers who fail to comply are subject to significant penalties, thereby providing an incentive so that a successful program permits utilities and

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[1] The dysfunction of the wholesale market is examined and described in "California's Electricity Options and Challenges: Report to Governor Gray Davis" by Loretta Lynch, President, California Public Utilities Commission and Michael Kahn, Chairman, Electricity Oversight Board, August 2, 2000. Also see the January 8, 2001 State of the State address of Governor Gray Davis.

the California Independent System Operation (ISO) to maintain system reliability and minimize rolling blackouts.[2]

SDG&E's program differs slightly from that of PG&E and SCE by providing discounts for rate periods when interruptions are not called, and setting higher rates when interruptions are called. Further, SDG&E's Schedule RTP-2 provides participants with 24-hours notice before an interruption is to take effect.

Table 1 shows the amount of traditional interruptible load during Summer 2000 for respondent utilities and the ISO, including cost, penalties, and program limits.

**TABLE 1**
**Summer 2000 Interruptible Load in Traditional Tariffs**

| ENTITY | INTERRUPTIBLE LOAD (MW) [1] | AVERAGE COST PER KW | PENALTY PER KWH | LIMITS |
|---|---|---|---|---|
| PG&E | 500 | $84 | $4.20 to $8.40 | 30 events<br>100 hours |
| SCE | 1,800 | $86 to $118 | $7.00 | 25 events<br>150 hours |
| SDG&E | 40 | $73 | $1.76 | 80 hours |
| ISO | 63 | $124 | $0 | 120 hours |
| Total | 2403 | | | |

[1] Approximate available interruptible load at peak.

Source: Energy Division Report, page 24.

[2] The California ISO operates most of the state's electricity transmission system. The ISO is responsible for monitoring the state's generation operating reserve, and notifying market participants and state agencies when an emergency is likely, or is called.

#### 2.1.2 Air Conditioner Cycling Plus Agricultural Pumping

SCE is the only investor-owned utility to offer an air conditioner cycling program. Under its program, the air conditioner unit is connected to the utility by radio. The utility transmits a radio signal to the customer's air conditioner when demand is high. The signal either turns the unit off for a specific amount of time, or cycles the air conditioner on and off over time (e.g., 10 minutes on and 20 minutes off).

The customer receives a rate discount for participating in the program. SCE's program is limited to 15 interruptions during the summer, with each interruption no more than 6 hours. SCE has approximately 282 MW of load subscribed to this program (245 MW residential, 37 MW commercial).

SCE also offers an agricultural pumping program, which functions similarly to SCE's air conditioner program. SCE has approximately 46 MW of load enrolled in this program.

#### 2.1.3 Demand Responsive Programs

These programs pay customers per interruption event rather than by rate discount. Participating customers are notified in advance when prices are expected to exceed specific levels. Customers may interrupt at least 20% of their load from a baseline set by the previous day's usage.

### 2.2 Experience

PG&E required its customers to join its traditional program for a minimum of 3 years, after which the commitment became year-to-year. Relatively abundant supply resulted in the Commission limiting PG&E's programs to only new customers beginning in 1993. That is, only new customers locating in the service area were allowed to enroll.

SCE required its customers to give 5-years notice before leaving its traditional program. The Commission limited SCE's program to only new customers beginning in 1996. SDG&E only required its customers to enroll in its program for one year at a time.

In 1998, with the start of electric restructuring, the Commission relaxed the 5-year notice requirement, and allowed both PG&E and SCE program participants to leave the programs during an annual "opt-out" period in November of each year. In October 2000, the Commission temporarily suspended SCE's opt-out provision given concerns over limited supplies. (D.00-10-066.)

At their request, we authorized both PG&E and SCE to reopen their programs for Summer 2000, with limited conditions. SCE reopened its program, and subscribed an additional 135 MW. PG&E declined to accept the conditions, however, and did not reopen its program. Further, about 124 MW opted-out of PG&E's program in November 2000. Table 2 summarizes available interruptible load in traditional programs as of January 1, 2001.

**TABLE 2**
**JANUARY 1, 2001 INTERUPTIBLE LOAD**

| UTILITY | INTERRUPTIBLE LOAD (MW) |
|---|---:|
| PG&E | 383 |
| SCE | 1,828 |
| SDG&E | 79 |
| Total | 2290 |

Source: Energy Division Report, page 31.

Energy shortages resulted in extensive use of the traditional interruptible programs in January 2001, thereby successfully avoiding many rolling blackouts. As a result, however, PG&E has nearly exhausted its 383 MW program for 2001, and SCE has used about half of its program.

### 2.3 ISO Interruptible Programs

The ISO offered two programs in 2000. The first is the ISO's Demand Relief Program (DRP). DRP is similar to the utilities' traditional interruptible programs, and compensates participants with both a flat monthly commitment fee, and a price for each kWh reduced. It is designed to attract new load not participating in any other program. Participants received an average payment of $124.00/kW and $2.50/kWh.

The second program is the ISO's Ancillary Services Load Program (ASLP). ASLP allows participants to bid their interruptible load into a market that may result in participants reducing load if operating reserves fall. The Commission prohibits participants of utility programs from also participating in the ISO's ASLP.

## 3. Curtailment Priorities Background

Utilities must implement mandatory outages if demand still exceeds supply after all available load reductions have been achieved through voluntary conservation and from interruptible customers. This is done by rotating outages through blocks of customers for approximately 60 to 90 minutes. These controlled, rotating outages are necessary to avoid system instabilities that could result in uncontrolled, system-wide outages, potentially involving not only California, but also parts or all of the interconnected western United States and Canada.

These plans go back to the 1970s. In 1973, there was a sharp reduction in the availability of fossil fuels for electric generation as a result of imported oil embargoes. At the same time, oil prices rose sharply. A drought the next year resulted in reduced availability of electricity from hydroelectric generation. To meet the potential shortages, the Commission issued decisions in 1973 and 1974 ordering that investor-owned electric utilities institute voluntary plans for conservation of electric energy, along with reduction of load by forced outage, if necessary.

The Public Utilities Code was amended in 1974 to require Commission adoption of a plan for allocating scarce electricity among customers in the event of shortages. (Pub. Util. Code §§ 2771-2776.) The Commission adopted a system of priorities for statewide reduction of electric service in 1976, with utilities filing necessary action plans. Utility action plans are filed, reviewed and revised annually.

A revised priority system was adopted in 1980. (D.91548, 3 CPUC2d 510.) As a result, specific entities providing essential services are exempt from rotating outages. These services include police, fire, prisons, national defense, some hospitals, and others. (See Attachment B for a complete list.) Since rotating outages are implemented by blocks of customers on electric circuits, many customers are exempt from rotating outages when they are on the same circuit as an essential customer.

The Commission's guiding principles for rotating outage plans are:

1. equitable distribution of the burden of outages;
2. no direct relationship between first outage and economic production, and
3. maximum load reduction early to avoid rotating outages if at all possible.

Commission adopted procedures for initiating rotating outages require that utilities have 40% of peak load available for rotating outages in 5% increments, so that at any one time up to 20% of customers may experience an outage of 60-90 minutes.

## 4. Proceeding Background

We instituted this rulemaking on October 5, 2000 to:

(1) "examine the role of customers on a utility's interruptible tariffs to ensure reliable and reasonably-priced electric service within California, especially for the Summer of 2001;

(2) coordinate the variety of interruptible, curtailable and demand responsiveness programs being offered and proposed in California;

(3) identify alternative means for customers to reduce their energy usage during periods of peak demand; and

(4) to revise and update the Commission's priorities for curtailing customers during times of energy shortages." (R.00-10-002, Ordering Paragraph 1.)

We proposed in the Order Instituting Rulemaking that the tariff provisions of PG&E, SCE and SDG&E allowing customers to opt out of interruptible programs during a 30-day window beginning November 1, 2000 be temporarily suspended. We invited comment within 7 days. (R.00-10-002, Ordering Paragraph 5.)

After giving careful consideration to all comments, on October 19, 2000 we issued D.00-10-066. By that order, we suspended until March 31, 2001 the portion of SCE's interruptible tariffs that allowed customers to either opt out of the program, or change their firm service levels, during a 30-day window beginning November 1, 2000. The California Manufacturers & Technology Association (CMTA) filed an application for rehearing on November 20, 2000. On March 15, 2001, we found no legal error in D.00-10-066, and denied the application for rehearing. (D.01-03-045.)

A prehearing conference was held on November 17, 2001. The Scoping Memo and Ruling was filed and served on December 12, 2000. The focus of the proceeding was set in the Scoping Memo and Ruling, with the centerpiece being staff recommendations in an Energy Division Report, followed by comments and reply comments from parties.

Leading up to Energy Division's Report, parties filed and served initial proposals on December 4, 2000; comments on initial proposals on December 11, 2000; additional proposals on December 14, 2000; additional comments on December 21, 2000; and supplementary proposals and comments on January 29, 2001.

We issued an emergency order on January 26, 2001 addressing potential jeopardy to public health, safety and welfare.[3] On February 6, 2001, a preliminary ruling was filed and served regarding eligibility for intervenor compensation awards. Also on February 6, 2001, an Assigned Commissioner's Ruling authorized limited public release of confidential or proprietary data and information submitted under Public Utilities Code Section 583 and General Order 66-C.

On February 9, 2001, the Energy Division filed and served its Report. Technical Conferences were held on the Report on February 15, 16 and 20, 2001.

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[3] D.01-01-056. We granted limited waiver of penalties for two public utility customers on interruptible rate schedules in response to a recommendation from the California Energy Commission (CEC). We suspended further assessment of penalties that customers on interruptible schedules would otherwise incur for failing to curtail upon request, along with the tolling of hours and number of curtailments. Finally, we directed respondent utilities not to bill customers for already incurred penalties, and to track all penalties in a memorandum account for the period from October 1, 2000 through January 25, 2001. We stated that we would later address whether or not past penalties would be waived. Applications for rehearing were filed on February 26, 2001 by SCE and The Utility Reform Network (TURN).

Further supplementary proposals and comments were filed on February 14, 2001. In particular, Joint Parties[4] filed and served a Joint Proposal on preservation of load curtailment program capabilities.

A motion for evidentiary hearing was denied by Ruling on February 20, 2001. On February 22, 2001, comments on the Energy Division Report were filed and served, along with reply comments on the Joint Proposal. On February 26, 2001, reply comments on the Energy Division Report were filed and served.

Public participation hearings were held on February 22, 2001 in San Francisco, February 26, 2001 in San Diego, February 27, 2001 in Santa Ana, February 28, 2001 in San Bernardino, and March 1, 2001 in Fresno.

On March 16, 2001, the Draft Decision (DD) of Presiding Officer and Assigned Commissioner Carl Wood was filed and served in accordance with Public Utilities Code Section 311(g)(1) and Rule 77.7 of the Commission's Rules of Practice and Procedure. On March 21, 2001, respondent utilities filed and served draft advice letters and tariffs to implement the decisions in the DD, as directed by Ruling issued March 1, 2001.

On March 21, 2001, another DD was filed and served. This DD proposed continuing the limited, temporary suspension of SCE tariffs adopted in D.00-10-066. Comments were filed and served on March 23, 2001, and reply comments were filed and served on March 26, 2001. That DD was adopted on March 27, 2001. (D.01-03-070.)

Emergency motions were filed on March 20 and March 21, 2001 asking for an immediate order to classify all hospitals as essential customers exempt from

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[4] Joint Parties for purpose of the Joint Proposal are PG&E, SCE, SDG&E, CMTA, California Industrial Users, and California Large Energy Consumers Association.

rotating outages. Hearing was held on these motions on March 22, 2001. By Assigned Commissioner Ruling (ACR) dated March 23, 2001, the motions were granted for hospitals with 100 beds or more, regardless of the status of backup or standby generation. We affirm the ACR, as discussed more below.

On March 27, 2001, respondent utilities were directed by ACR to notify essential and non-essential customers reclassified between June 1, 2000 and the date of the notice. Further, respondent utilities were directed to notify customers of future reclassifications before the reclassification would become effective. We affirm the ACR, as discussed more below.

By ACR dated March 28, 2001, an emergency motion filed by the City and County of San Francisco (CCSF) was granted. PG&E was directed to provide limited information to the Commission, for Commission release to CCSF under strict conditions, which CCSF may use to minimize the impact of rotating outages. Further, SCE was directed to meet with the City of Huntington Beach to determine what data not already provided can be reasonably provided to help Huntington Beach meet its public health and safety obligations during a rotating outage. We affirm the ACR.

Motions for final oral argument were filed and served on March 14, 2001. Final oral argument was held on March 22, 2001. Comments on the March 16, 2001 DD, including comments on the draft advice letters and tariffs, were filed on March 26, 2001, and reply comments were filed on April 2, 2001. We incorporate changes to the March 16, 2001 DD in today's order based on the entire record before us, taking everything into account including final oral arguments, comments, and reply comments. Unless discussed otherwise, we affirm rulings made by the Administrative Law Judge and the Assigned Commissioner.

## 5. Adopted Improvements to Current Interruptible Programs and New Programs

Parties' comments and reply comments on the Energy Division Report, plus the March 16, 2001 DD, were extensive and constructive. We concentrate in the following sections on our adopted programs and the chief points of contentions. We do not try to summarize or address every argument or nuance in the comments and reply comments.

### 5.1 Opt-Out and Realignment of Firm Service Level

Probably the most contentious issue is whether or not to continue the temporary suspension adopted in D.00-10-066 of the portions of SCE's interruptible tariffs that would otherwise allow customers to either opt out of the program or change their firm service level. For the many reasons stated by nearly all parties who addressed this issue, we are persuaded to allow SCE's customers to opt-out or change firm service level without complicated conditions. We allow customers to select an effective date for this change of either November 1, 2000, or the date consistent with the beginning of their next billing cycle.[5]

The underlying premise of SCE's program was that interruptible customers were allowed to opt out or change firm service level with advance notice of five years. This five-year notice was modified in 1998 to an annual opt-out or change in firm service level because of the transformation of the electricity

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[5] SCE typically implements an opt-out or change in firm service level at the time of the next billing cycle. As discussed below, we do not limit the customer and SCE agreeing to an earlier date if they wish, and we in fact encourage the customer and SCE to agree to an earlier date.

market (e.g., deregulation, creation of ISO and Power Exchange). Customers began to rely on the ability to reassess their situation annually.

We temporarily suspended the annual opt-out or change in firm service level option in D.00-10-066 while we considered matters further. We are now persuaded to lift the suspension.

Interruptible customers say they used reasonable and realistic assumptions in their analyses, and made careful judgments of risks and rewards, before making decisions about opting out or adjusting firm service levels. They argue that the electricity system is now operating outside any reasonable bounds that could have been used in their analyses, and that this fact justifies allowing customers to opt-out or readjust.

We agree. The electricity system is operating outside any reasonable bounds, or any realistic assumption customers could have been expected to use.

For example, on January 17, 2001, Governor Gray Davis proclaimed a State of Emergency. This proclamation is based on electricity shortages resulting in blackouts for millions of Californians, and dramatic increases in electricity prices threatening the solvency of California's major public utilities. The Governor also found that the imminent threat of widespread electricity disruption constitutes a condition of extreme peril to the safety of persons and property within the state. Among other things, he directed the California Department of Water Resources (DWR) to begin procuring electricity to mitigate the effects of the emergency. It is unlikely that any customer could have realistically foreseen such dramatic events as those that led the Governor to declare a State of Emergency.

Nine days later, the threat to public health and safety justified our suspending penalty provisions for failure to curtail when requested by the utility, along with the tolling of hours and number of curtailment events. (D.01-01-056, January 26, 2001.) We said:

> "Interruptible customers now face increasingly serious consequences of being on interruptible tariffs, despite their voluntary choice to have subscribed for interruptible service, and their obligation to abide by the terms of the tariff…The continuing electricity crisis, however, requires that we reassess the operation of our interruptible programs.
>
> "These customers face the ongoing choice of curtailing electric service, or paying significant penalties. If they curtail service, for many customers this means closing their operations or businesses, with deleterious effects on themselves and the California economy. The harmful effects include lost sales, lost revenues, lost productivity, foregone wages, layoffs, unemployment, business not expanding in California, and businesses moving out of California. For some customers, such as hospitals and prisons, this choice threatens public health and safety. Alternatively, customers can continue to operate and incur large penalties. These penalties may threaten the financial integrity of their operations and businesses, and have the same deleterious effects on the California economy.
>
> "Neither alternative is acceptable. Customers essentially face an irreconcilable dilemma." (D.01-01-056, mimeo. page 5.)

Thus, market conditions have dramatically changed from those that existed in prior years.

Normal changes also justify lifting the suspension. That is, businesses and other customers (e.g., universities) grow, modify processes, and make other changes over time. It is reasonable to allow customers to periodically reassess their situations and either opt-out or change firm service levels to better match current market and business realities with their abilities to interrupt load.

Lifting the suspension now will allow customers to make necessary and reasonable changes. Among other things, this will permit respondent utilities and the ISO to have a more reliable base of interruptible load for Summer 2001. We believe that this will give utilities and the ISO more knowledge of the truly available interruptible resources from which to manage conditions this summer, without relying on or expecting penalties to drive customer compliance. We believe perfecting the base for Summer 2001 is further justification for lifting the suspension now.

We are also persuaded by several customers that SCE marketed its interruptible program differently than did PG&E or SDG&E. Addressing these differences now simply distracts us, SCE and its customers from the immediate task of finding workable solutions for Summer 2001. We think lifting the suspension now promotes the best opportunity for current and future participation.

We decline to adopt the limited opt-out or adjustment in firm service level proposals in the Assigned Commissioner's March 16, 2001 DD. Those proposals would allow opt-out or readjustment based on one of four methods.[6] The methods are creative, and would seek to promote desirable and equitable outcomes for Summer 2001. We choose, however, to focus on new programs and solutions for Summer 2001 rather than restructuring prior obligations to meet current market realities.

Moreover, each particular method presents complications. For example, the first three methods involve potentially complex and controversial

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[6] The four proposed methods are: (1) the customer would pay back discounts received in 2000 and 2001, with interest; (2) the customer would invest in and install certified energy efficiency equipment by July 1, 2001 in an amount of money equal to or greater than the total discount in 2000 and 2001, with interest; (3) the customer would participate in the Commission's pay-for-performance program providing the same amount of kWh load reductions that would be required under SCE Schedule I-6, but be subject to penalties in some cases; or (4) some customers could opt-out or readjust without condition.

calculations. In addition, some parties point out that option one creates inequities between a customer who has complied with interruptions and one who has not. Other parties point out that under the second option the equipment which is or is not certified as energy efficient for this purpose is not well defined, and it is unclear what happens if the customer fails to invest to the required level by July 1, 2001. Further, they state that it will take time to engineer, order and install such equipment, and some, if not many, customers cannot meet the July 1, 2001 deadline.

According to some parties, calculation of the equivalent kWh for another program based on what would have been required under SCE Schedule I-6 presents opportunity for interpretation and disputes under the third option. Finally, other customers might realistically ask to be included in the unconditional fourth option.

While more precise formulas, additional rules, deadline extensions, and other remedies, might be devised, we decline to try to perfect the four options. Rather, we believe the limited time and resources of the parties and Commission are best devoted to more positive solutions for Summer 2001.

As a result, we lift the suspension of the opt-out or change in firm service level options. We allow customers to elect to opt-out or change firm service level during a 15-day window beginning upon service of notice to customers of this option. SCE must provide written notice to each affected customer within 10 days of the date the tariff becomes effective, including a calculation of the effect of selecting the November 1, 2000 date. In addition to this opt-out or readjustment, lifting the suspension means customers may annually reassess and make changes as necessary beginning in November 2001.

We allow the customer to choose the effective date of the current opt-out or adjustment. The date may be either November 1, 2000, or a date consistent with the beginning of the next billing cycle.[7] We allow the choice back to November 1, 2000 since many customers would have selected this time period in November 2000 if it had not been temporarily suspended by D.00-10-066. Moreover, the market became particularly chaotic in November 2000, when the number of Stage 2 and Stage 3 events began to increase.[8] The November 1, 2000 date, however, requires that the customer repay the discounts received from November 1, 2000 through the present, but not pay any otherwise incurred penalties for failure to curtail when asked during that time.

An election in November 2000 to opt-out or change firm service level would not have resulted in a change until shortly after November 1, 2000. While we could order the date that would have otherwise resulted, such approach would make this option unreasonably complicated. A uniform date will promote administrative ease, customer understanding, and minimization of disputes. On balance, it is desirable to essentially let customers undo the

[7] We do not limit the ability of the customer and SCE to select a date earlier than the beginning of the next billing cycle if they wish, however. In fact, we encourage the customer and SCE to select an earlier date if feasible to allow opt-out or realignment as soon as possible. This date may be between the date of notice by SCE of the option, and the beginning of the next billing cycle. We focus on the beginning of the next billing cycle only because that would appear to promote consistency with SCE's current practice, and is an outside date by which this change should be accomplished.

[8] The California ISO declares a Stage 1 emergency when forecast or actual operating reserves are less than 7% of available capacity. A Stage 2 emergency is declared when forecast or actual operating reserves fall below 5% of available capacity. A Stage 3 emergency is declared with forecast or actual operating reserves fall below 1.5% of available capacity. The California ISO may call for rotating outages during Stage 3 emergencies.

temporary suspension if they wish, but not make it unnecessarily complex. For the same reason, we decline to order collection or payment of interest.

Alternatively, the customer may opt-out or change firm service level effective with the beginning of the next billing cycle. This is consistent with SCE's current practice, and will promote consistency and simplicity. A customer electing this option will retain the rate discount for interruptible service through the date of any change in schedule or firm service level. The customer will, however, be obligated to pay any penalties incurred for failure to interrupt when asked by the utility under the interruptible schedule through the time the opt-out or adjustment in firm service level is effective.[9] As described below, penalties that might otherwise occur from the reinstatement of penalties with this decision until the effective date of the opt-out or change in firm service level will be waived.

Further, for reasons explained below, we do not allow customers who opt-out during this 15-day window to participate in the ISO's DRP and Ancillary Services Load Program. We also decline to allow such customers to participate in any other respondent utility program that pays a capacity payment (i.e., the new base interruptible program described below). This limitation will prevent unreasonable turnover between similar programs without benefit to the state.

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[9] That is, any penalties incurred up to and through November 2000, as well as though January 25, 2001, would be due and payable. This option, however, does not change D.01-01-056. That is, penalties are suspended effective January 26, 2001 until lifted going forward by this decision. This option does not require the customer to pay any penalties that might otherwise have been due from January 26, 2001 through the date the penalties are reinstated.

### 5.2 Other Modifications to Existing Programs

We make other modifications to existing programs, largely as recommended by Joint Parties. First, we extend the programs of PG&E, SCE and SDG&E to December 31, 2002. Existing tariffs are otherwise scheduled to expire (sunset) on March 31, 2002. We agree with Joint Parties that the need for these programs is unlikely to end in 2001, or by March 31, 2002. To the extent these programs are successful, they should be continued at least through the Summer of 2002, and we think reasonably to December 31, 2002.

At the same time, many structural changes are being made to the electricity market. We hope these changes will soon be successful in realigning demand and supply, and bringing prices back to just and reasonable levels. Interruptible programs are very expensive. We cannot reasonably extend expensive programs without limit. Rather, we extend the sunset for a specific, limited duration to December 31, 2002, and will reconsider extensions and program redesign as necessary for use beyond December 31, 2002.

We also limit program use to one 6-hour event per day, 4 events per week, and 40 hours total per month. We do this to reasonably extend the programs in light of the experience in January 2001. In January 2001, interruptible customers were asked to curtail load almost continuously. As a result of that experience, in late January 2001 we suspended interruptible program penalties, along with the tolling of events and hours. (D.01-01-056.) PG&E's program was almost completely exhausted before it was suspended.

PG&E and SCE customers were in particular pressed to the limit by the number and duration of interruption calls. Customers faced an irreconcilable dilemma of choosing to curtail electric service almost continuously, or paying significant penalties. (D.01-01-056, mimeo., pages 5-6.) This is simply not acceptable. It places unreasonable expectations on customers, and too quickly exhausts programs in a manner not necessarily in the best interests of the State. As a result, we limit exposure to interruptions to reasonable limits per day, week and month so that the remaining portions of these programs are useful for the remainder of 2001 and 2002, without unreasonable burdens on customers.

Joint Parties propose that the utility may terminate the customer's subscription under the interruptible tariff and return the customer to the otherwise applicable rate schedule if the customer does not achieve its firm service level for three consecutive curtailment events. We decline to adopt this proposal. This vehicle could otherwise be used strategically by a customer to transfer to another rate schedule without reasonably fulfilling its obligations. We think the better approach is to make existing programs more reasonable, as we do above, including limited opt-out and firm service level adjustments available during a 30-day window.

SDG&E asks that we adopt reasonable limits on interruptions for Schedules AV-1, A-V2, and RTP-2. In support, SDG&E says a unique provision in its interruptible tariffs requires SDG&E to interrupt customers during a system emergency even when the customers have reached their maximum hourly limit. For example, in January 2001, SDG&E says customers on its Schedules A-V1 and A-V2 were notified of the need to interrupt almost every day. According to SDG&E, this notice led many customers to terminate service on these schedules because of the undue hardship.

SDG&E points out that Schedules A-V1 and A-V2 now contain an annual limit of 80 hours of interruptions when SDG&E's system load exceeds a prescribed level. According to SDG&E, however, none of the interruptions this year have been due to SDG&E system load exceeding the prescribed level. Rather, SDG&E says all curtailments were called in accordance with the system emergency clause in SDG&E's tariffs, which requires SDG&E to curtail interruptible customers when the ISO calls for such interruptions during Stage 2 and 3 events. SDG&E asserts that this clause is unique to SDG&E's interruptible tariffs.

SDG&E says customers have simply begun to shift off of these interruptible tariffs because there are no limits to the amount of curtailments that SDG&E can call in the event of a system emergency, and there seems to be no end in sight for ISO-called emergencies. SDG&E interruptible customers can opt out from interruptible service at any time after being on the rate for 12 months. As a result, SDG&E says more customers will move to firm service absent a fixed annual limit to curtailments. SDG&E recommends that the Commission delete the "emergency circumstances" exception and adopt fixed annual limits. We agree in part.

We retain the emergency circumstances exception in SDG&E's tariffs to allow response to statewide emergencies. At the same time, however, we limit the customer's exposure to all interruptions, including the emergency circumstances, to 120 hours per year. We increase the limit from 80 hours because the emergency circumstances exception allowed more exposure than 80 hours, and we think reducing the exposure to 80 hours now in the face of a possibly difficult Summer 2001 would be unreasonable. PG&E's program is limited to 100 hours of interruptions, and SCE's program is limited to 150 hours. We think 120 hours is, on balance, a reasonable maximum for SDG&E customers, bringing the exposure from an unlimited amount to a level comparable to that faced by other respondent utility customers. This is also reasonable in light of the limits we adopt above on the exposure per day, week and month.

SCE asks that we clarify that the extension of existing programs means they are reopened for all customers. We decline to do that. Rather, for example, existing and new customers not in an existing program should consider the new base interruptible program, or other programs described below. On the other hand, we specifically identify the programs herein when they are reopened to existing and new customers (e.g., SCE's air conditioning cycling program).

### 5.3 Insurance

We also address the issue raised by Caliber One Indemnity Company (Caliber One). Caliber One requests a Commission determination of whether or not interruptible customers have the option of willfully refusing to comply with interruption notices without breaching their obligations. Caliber One contends that willful refusal to curtail undermines or defeats the goals of the interruptible service program, or renders an interruptible tariff and its rate structure unlawful, unjust, unreasonable, or discriminatory. Caliber One raises this concern in particular with SCE's Schedule I-6. Additionally, if the Commission finds such behavior constitutes breach or violation, Caliber One requests that the Commission act to fix the Schedule I-6 tariff, interruptible rate contracts, and, if deemed appropriate, the insurance policies between SCE's customers and Caliber One.

We agree with PG&E's response on these issues. (February 26, 2001, page 4.) There is nothing in current interruptible tariffs that limits a customer's right to continue using electricity during curtailment periods. The customer makes the choice to curtail or not curtail based on any number of factors, including safety and economics. Customers are subject to substantial penalties for failing to curtail, however, and apply appropriate caution when making such decisions.

Caliber One asks that the Commission "determine, at a minimum, whether willful refusal to comply with Interruption Notices constitutes a breach of the Interruptible Service Contract and renders the I-6 Tariff and its rate structure unlawful, unjust, unreasonable or discriminatory." (Opposition of Caliber One, March 2, 2001, page 2.) We find that under current interruptible tariffs it does not.

Moreover, we agree with PG&E that the existence of this contract right not to curtail has been crucial to the efficient and effective administration of this program. For example, the existence of this provision has forestalled a great number of separate petitions for individual tariff deviations that might otherwise have been engendered over the course of each summer during which these programs have been operated.

Caliber One cites Public Utilities Code Sections 701, 728 and 743(f) in support of its position, alleging that these sections give the Commission jurisdiction over the insurance agreement between an SCE customer and Caliber One. We disagree for the reasons stated by SCE and the Internal Services Department of County of Los Angeles (ISD/LAC).[10] These code sections give the Commission authority to regulate public utilities. Customers of SCE are generally not public utilities.[11] Caliber One does not claim to be, and is not, a public utility.

We also regulate contracts between utilities and customers to ensure that:

> "…utility management has not agreed to provide service under unreasonably favorable terms and conditions to the contracting individual or entity. Such an agreement, potentially subsidized by customers subject to regulated rates, would indicate management was acting to violate Pub. Util. Code §§ 451 and 453 which, respectively, prohibit unjust and unreasonable rates

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[10] SCE Comments December 21, 2000, page 6. ISD/LAC Motion to Strike Statement of Issues of Caliber One, February 20, 2001, page 4. Reply of LAC, March 8, 2001, page 2.

[11] Limited exceptions include water districts and pipeline companies.

> and undue discrimination among customers." (D.99-07-014, 1999 Cal. PUC LEXIS 481.)

We may require a public utility to file contracts between the utility and its customers. We may examine a private contract to the extent it is between a utility and a customer and might involve utility violations of the Public Utilities Code. The contract between a utility customer and an insurance company, however, even if it incorporates a regulated tariff, does not fall into this category.

Caliber One contends that the Commission must determine whether the Schedule I-6 tariff is unlawful, unjust, unreasonable, discriminatory or preferential when customers willfully refuse to curtail, including "rules, practices or **contracts** affecting such rates or classifications…"(Pub. Util. Code § 728, emphasis added). Caliber One argues that the insurance policies and agreements incorporate the Schedule I-6 tariff, and thereby bring the insurance contract under Commission jurisdiction. We disagree. We regulate the terms and conditions of interruptible tariffs, and contracts between utilities and customers. We do not regulate agreements between a customer of a public utility and another party, third party contracts not involving a public utility, or agreements between non-public utilities, whether or not the agreement references a regulated rate or tariff.

Caliber One asks that parties be given a chance to submit written comment on the issue framed by Caliber One's intervention. While we could give additional notice and opportunity for comment, we will not burden parties and the Commission further on this matter. Parties had the opportunity to file responses to the December 14, 2000 Caliber One motion to intervene and statement of issues. Parties had the opportunity to address Caliber One's issue in additional comments filed and served on December 21, 2001.[12] Caliber One raised its issue in comments filed on the Energy Division Report. Parties had the opportunity to file reply comments on February 26, 2001.[13] Moreover, ISD / LAC filed a motion on February 20, 2001 to strike Caliber One's statement of issues, Caliber One responded in opposition on March 2, 2001, and LAC replied on March 8, 2001. Adequate notice and opportunity to comment have been given on this issue. We need nothing further from parties on either our jurisdiction or their recommendations before we make our decision.

We address one aspect of this issue going forward. There is no dispute that the Commission has jurisdiction over interruptible tariffs, and eligibility for those tariffs. We find that current tariffs do, and future tariffs should, allow customers to make the decision whether or not to curtail.

We agree with Caliber One that willful refusal to curtail, however, may defeat the public purpose goal of the interruptible program in the specific instance where the customer shifts the risk of penalties from itself to others by use of an insurance policy. We do not expect customers to subscribe to an interruptible tariff for the purpose of obtaining a rate discount but with no intention of honoring an interruption request. Customers now and in the future may willfully refuse to interrupt for any number of reasons, and pay the penalty. Unless there are reasonable eligibility restrictions, however, some customers might buy insurance against non-compliance penalties. This could result in the interruptible customer failing to interrupt to the detriment of all other ratepayers.

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[12] For example, SCE did so on December 21, 2000 at pages 5-6.

[13] For example, PG&E did so on February 26, 2001 at pages 4-5.

To cure this possible defect, we adopt SCE's proposal to modify eligibility for interruptible tariffs by way of a declaration. Existing and new customers will not be eligible for continued or new subscription to interruptible tariffs unless they file a declaration under penalty of perjury with the utility. The declaration must state that the customer does not have, and will not obtain, any insurance for the purpose of the insurance paying non-compliance penalties for willful failure to comply with requests for curtailment. Any customer with this insurance after the effective date of this tariff eligibility condition will be terminated from the tariff, and will be required to pay back the rate discount for the period covered by the insurance. If the period cannot be determined, the recovery shall be for the entire period the customer was on the tariff.

Respondent utilities shall provide written notice to each potentially affected customer of this condition within 10 days of the effective date of the tariff. The declaration will be due to be filed with the utility within 30 days of the service of notice, and this tariff condition shall become effective 30 days after service of notice to the customer.

There may be situations where insurance is still reasonable, however, such as loss of business, or damage resulting from a curtailment. Insurance may be obtained for such other purposes.

### 5.4 Lift Suspension of Penalty Provisions

With these modifications and improvements to the interruptible tariffs, we lift the suspension of penalty provisions imposed by D.01-01-056. That is, the tariffs filed pursuant to this interim order shall include penalty provisions for interruptible electricity service customers when a customer fails to curtail for any reason at the request of utility. The tariffs shall include the tolling of hours and number of curtailment events against program maximums, and any other related elements of the tariffs, which were suspended by D.01-01-056. Each respondent utility shall notify each affected customer within 3 days of the date the tariff becomes effective. The penalties, tolling of hours, tolling of numbers of curtailment events, and other provisions, will become effective 3 days after the date of service of the notice.

These reinstated penalties will not apply, however, for any customer who opts-out effective November 1, 2000 and repays discounts. Similarly, these penalties will not apply from November 1, 2000 forward to the extent the change in firm service level negates penalties, and discounts are repaid.

Further, reinstated penalties will not apply, or will be waived, for any customer who opts-out or changes firm service level (to the extent the change in firm service level negates the penalty) going forward. This is, reinstated penalties will not apply from the date reinstated (e.g., 16 days from today) through the date the opt-out or change in firm service level is effective (i.e., the beginning of the next billing cycle).

### 5.5 New Base Interruptible Program

The Energy Division Report shows that traditional interruptible programs give reliable load reductions, and important benefits to both interruptible customers and the State. For example, PG&E’s program has a very high compliance rate with about 400 MW of interruptible load. SCE has had a lower compliance rate, but has produced about 1,200 MW of dependable interruptible load. SDG&E has had good compliance with about 40 MW of interruptible load. Interruptible customers have enjoyed about $220 million per year in reduced rates or payments, and the State has had the benefit of over 1,600 MW of performing interruptible load.

PG&E's program has been nearly fully exhausted for 2001, however, based on its extensive use in January 2001. Similarly, SCE's program is about half exhausted, and may be fully exhausted in a few months. Further, a new program may be more attractive to some new customers than the existing program. Thus, a replacement program is necessary.

Therefore, we adopt a modified version of the "enhanced interruptible program" proposed by Joint Parties. (Item II.B.4 in the February 14, 2001 Joint Proposal.) To distinguish this from other programs, we call this the new Base Interruptible Program (BIP). This program will be operative all year. Program details are stated in Attachment A.

Among other benefits, this program provides some security of monetary benefit (i.e., a fixed capacity payment in dollars per kW-month). This type program has a place in an overall portfolio of programs. For example, customers who incur up-front costs for program participation (e.g., investment in equipment or facilities to produce load reductions) are assured of at least some financial return for making their resources (i.e., load reduction) available.

We decline to adopt the provision that three consecutive failures to comply will result in the participant being removed from the program. For the reasons stated above, we believe this provision may be used strategically by a customer to transfer to another rate schedule without reasonably fulfilling its obligations. That is, after obtaining several months of benefits, a customer might fail to comply in order to be transferred. Under some conditions, the customer would benefit, but other ratepayers would not. As a result, we do not adopt this provision absent further information to assure us of its reasonableness.

### 5.6 Voluntary Demand Response Program

We also adopt a modified version of the "day ahead" and "day of" programs proposed by Joint Parties. (Items II.B.1 and II.B.2 in the February 14, 2001 Joint Proposal.) To identify this program from other programs, we call this the Voluntary Demand Response Program (VDRP). This program will be operative all year. Program details are stated in Attachment A.

Among other benefits, this program provides flexibility for customer participation, with payments based on performance. This type of program also has a place in an overall portfolio of programs.

This program will be implemented by respondent utilities. We decline to adopt a price determined by the "market" (e.g., bidding by participants, or reliance on a "market maker" such as an entity like the former Power Exchange). We do not use a market approach since we are not convinced we have an efficient market which will result in just and reasonable prices.

At the same time we are convinced by parties that we need a reasonably simple approach for this program to be successful. Most customers, even big customers, state that their business is conducting their business, not buying and selling electricity, and not constantly monitoring the electricity market to make decisions about buying electricity or curtailing their operations.[14] We determine

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[14] For example, Arrowhead Mountain Spring Water Company says: "While some of the suggestions for bidding interruptible load or back-up generation into the market sound intriguing, Arrowhead's business is bottling water, not selling interruptible load or electric capacity. It is not realistic to expect industry to routinely develop the interest and capacity to perform market trading functions." (February 21, 2001 Comments, page 5.) We agree. We heard from many customers that they do not want to be considered part of California's electricity resource base by being expected to constantly interrupt service. Interruptible programs are a second best solution. The first best solution is for safe, reliable electricity to be available at reasonable rates. This may in some limited

*Footnote continued on next page*

that a fixed rate is necessary, subject to modification as needed, to balance efficiency and simplicity.

We decline to adopt Energy Division's recommendation of $0.15/kWh as too low given the reality of prices in the currently dysfunctional market. We similarly decline to adopt Joint Parties recommendation of $0.50/kWh to $0.75/kWh as too high. While prices are in this high range (or even higher) at some times in today's broken market, we cannot sanction continuation at these unacceptable levels. Moreover, we reject Joint Parties recommendation of $0.50/kWh for day ahead, and $0.75/kWh for day of, markets. A dual rate is needlessly complex, and will unreasonably encourage customers to withhold supply, waiting for the higher rate.

We balance competing proposals and adopt a rate of $0.35/kWh. This rate may be offered on a day ahead, or day of, basis as respondent utilities determine necessary, reasonable and useful. Respondent utilities may accept or reject bids based on need, order received, and experienced reliability with the customer.

Participating customers will enjoy not only the $0.35/kWh, but also the savings for the amount of electricity they do not buy from the utility. If an energy rate otherwise not paid is $0.05/kWh, for example, the customer enjoys a total of $0.40/kWh.

Respondent utilities may file advice letters as necessary to adjust this rate. Because we need to respond with some dispatch, we will reduce the protest

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applications involve customers actively trading in the electricity market, or being part of the resource base by constantly interrupting consumption. For the most part, however, customers are interested in doing, and should do, whatever it is they want and need to do with electricity, not becoming electricity traders or implementing constant interruptions.

period to 10 days. Based on the urgency for a rate change, we may also reduce the comment period on the draft resolution at the time it is issued.

If particularly urgent conditions exist, a party may file an urgent or emergency petition for modification. The petition may seek an immediate order increasing or decreasing the adopted $0.35/kWh rate. If necessary, the Assigned Commissioner may rule on the petition by ACR, with Commission approval or confirmation as soon as reasonable thereafter.[15]

We will not authorize rate adjustments often, however, absent exceptionally compelling justification. Rather, we seek to promote stability at a reasonable rate in this market. If anything, we think $0.35/kWh may be unreasonably high, and we look forward to the market stabilizing at a lower rate, with utilities or parties filing advice letters or petitions to lower the rate. We will consider rate increases, however, if the market continues to be dysfunctional, and higher rates are needed to promote public health, safety, welfare and system reliability.

Customers incur cost and inconvenience for participating in this program. As a result, we adopt a modified version of Joint Parties recommendation for a minimum payment to promote equity and efficiency. It is equitable to compensate customers for at least some of their cost and inconvenience for participation. Moreover, without some minimum payment, we are persuaded by parties that fewer customers will participate, and some efficiency would be lost. Thus, once a bid is accepted, we authorize respondent utilities to pay the

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[15] Pub. Util. Code Section 310. This is the approach used with the emergency motions filed March 20 and 21,2001, with the ACR on March 23, 2001, which we approve and confirm herein.

customer even if the interruption is cancelled at the lesser of the hours bid, the hours requested, or 2 hours.

SDG&E expresses concern that the criteria for VDRP (as well as BIP) require a minimum of 670 kW of average demand (i.e., a reduction of at least 15% of load, with a minimum load drop of 100kW). SDG&E points out that the minimum demand requirement in the Joint Proposal is 300 kW, with the minimum load drop the higher of 100 kW or 15% of demand. Further, SDG&E says the Joint Proposal allows utilities to lower the minimum at their discretion. SDG&E asserts that limiting participation to customers larger than 670 kW means the programs will be available to fewer than 500 customers in SDG&E's territory, severely reducing the potential for program success. SDG&E seeks modification of the March 16 DD to reflect its smaller customer base.

We clarify that the adopted programs allow a minimum of 100kW, not 300 kW or more. Application of the 15% minimum means that a 100 kW customer would need to drop 100% of its load to participate, and a 300 kW customer would need to drop 33% of its load to participate.

Moreover, we go beyond the 300 kW minimum recommended by Joint Parties, and reduce the minimum to 100 kW to seek maximum participation. We decline to allow utilities to further modify the threshold at their discretion. Rather, we seek some uniformity in programs, and will adjust minimums based on experience as petitions, motions, proposals and other pleadings are brought to our attention.

### 5.7 Air Conditioner Cycling Programs Plus Agricultural Pumping Programs

We adopt Joint Parties recommendation to allow respondent utilities to reopen and expand current air conditioner cycling programs for residential and commercial customers. Since only SCE has an existing program, we authorize

SCE to reopen its current program to all residential and commercial customers at all cycling options.[16] (See Attachment A.)

SCE's current program is limited to 15 interruptions of up to 6 hours. We are persuaded that additional options are necessary. Therefore, we adopt Energy Division's recommendation and authorize SCE to offer a new program.

The new program will pay double existing rates for an unlimited number of events, but no more than 6 hours of interruption in any one day. It will offer the same cycling options now offered (i.e., 50%, 67%, and 100% for residential; 30%, 40%, 50% and 100% for commercial).

We adopt the 6 hour limitation because we are convinced by TURN and others that satisfaction and participation will decline if the program is overused. At the same time, we balance competing interests and decline to adopt a limitation that the program cannot be used more than 3 days in a row for any one customer. If the program is needed, it must be available to the State. We rely on customers electing the cycling option (e.g., less than 100%) with a limitation of 6 hours per day as a reasonable balance.

We decline to adopt Energy Division's recommendation that a customer may increase, but cannot decrease, the commitment. Rather, if a customer enrolls in 100% cycling but is unable to meet that commitment, we allow the customer to downgrade once at no cost within 12 months, just as allowed in SCE's existing program. A customer may increase the cycling percentage at any time without cost.

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[16] We authorize 50%, 67% and 100% cycling options for residential customers, and 30%, 40%, 50% and 100% cycling options for commercial customers.

We decline to adopt TURN's recommendations to limit the number of events to 10 per month. Customers who desire limits can subscribe to the current program, which we reopen. The higher prices offered in the new program justify this variation, which complement the limits in the existing program at lower prices.

Similarly, we do not eliminate the 100% cycling option as TURN recommends. We recognize TURN's concern that 100% cycling may be too severe for some customers, and result in poor customer satisfaction and retention. In response, we provide the option to downgrade once at no cost within 12 months. Moreover, we direct SCE to make a reasonable effort to inform customers of the effect of the 100% option, and how that may or may not be compatible with other requirements. For example, many buildings have closed air circulation systems. The 100% cycling option may compromise air quality in relation to state standards. SCE must raise this issue with customers when marketing the program, and let the customer determine which, if any, cycling options will produce a satisfactory result.

PG&E and SDG&E continue to object to air conditioner cycling programs, claiming they are not cost-effective, and that neither utility has the necessary infrastructure for program rollout. We are not convinced.

The CEC estimates that 14,000 MW of air conditioning load (28% of total load) occurs during the state's summertime peak demand of 50,000 MW, with about 7,000 MW (14% of total load) commercial, and about 7,000 MW (14% of total load) residential. Nearly 5,000 MW of reduced load could be achieved at peak if all air conditioners could be cycled at 33%, or if 33% of air conditioners could be cycled at 100%.

TURN strongly advocates air conditioner cycling programs as a cost-effective option. Comverge Technologies, Inc. reports that it can provide full responsibility for turnkey projects. Comverge says it can take the financial risk on a pay-for-performance basis, and can use existing paging companies for radio communication. Moreover, signals can be used with a wide range of appliances, from air conditioners to electric water heaters, pool pumps, or other electric motors in residential, commercial or industrial settings.

This is a potentially vast, untapped source of interruptible electricity. Properly partnered with companies such as Comverge, respondent utilities and ratepayers can enjoy benefits with the providing company taking the financial risk. This opportunity needs further exploration.

Therefore, we order PG&E and SDG&E to explore reasonable options for implementing air conditioner cycling, and other electric motor interruption, programs targeted to residential and commercial customers. We similarly order SCE to explore reasonable alternatives for implementing an electric motor (in addition to air conditioner) interruption program, targeted to residential and commercial customers.

PG&E, SCE and SDG&E shall each file and serve an advice letter no later than May 1, 2001. The advice letter shall analyze and report on alternatives, and seek approval of the most reasonable alternatives, including proposed tariffs for implementation. The analysis of each alternative shall include cost, amount of load reduction, means to verify load reductions, and timeliness of implementation.

We caution PG&E and SDG&E that we are convinced one or more air conditioning cycling programs should be approved in each service area. This is the opportunity for PG&E and SDG&E to propose what each believe are the best options for their areas. That is, the advice letters of PG&E and SDG&E should seek approval of the options that each utility finds most reasonable.

We similarly adopt Joint Parties recommendation to reopen current interruptible tariffs for agricultural and pumping customers. SCE's tariff was generally closed to new customers in November 1996. We reopen SCE's interruptible tariff to all agricultural and pumping customers. Further, it is due to expire March 31, 2002. We extend it to December 31, 2002, just as we do above for all existing interruptible programs.

### 5.8 Optional Binding Mandatory Curtailment Program

Parties generally support an Optional Binding Mandatory Curtailment (OBMC) program if it is properly designed and operated. We adopt the OBMC program stated in Attachment A.

An OBMC program exempts customers from Stage 3 rotating outages in exchange for partial load curtailments during every rotating outage period. The customer is required to file an acceptable binding energy and load curtailment plan with the utility in which the customer agrees to curtail electricity use on its entire circuit by specified amounts. The customer's plan must show how reduction on the entire circuit can be achieved in various increments, and how compliance can be monitored and enforced. The burden is on the customer to demonstrate that the proposal is realistic, workable, measurable, and enforceable. At the same time, we direct respondent utilities to use the OBMC program as an opportunity to work with each interested customer to reach a solution not only in the best interest of that customer, but in the overall best interest of the electrical system.

The program protects large customers from the significant economic harm they might otherwise experience during a rotating outage. OBMC customers receive no payment. Rather, they benefit by exclusion from rotating outages. While this does not eliminate exposure to all outages (e.g., an unplanned or forced outage such as from a transmission line or transformer failure), it does eliminate exposure to Stage 3 rotating outages.

The current OBMC requires a plan showing load reductions by increments of 5% percent, up to a total of 20%, on the entire circuit. The 20% level corresponds to the total load that might be subject to rotating outage at any one time under our existing program.

We are persuaded by many parties, however, that 20% for OBMC is simply too onerous, and will substantially reduce the ability of customers to use this program. We must balance our overall system goal of up to 20% with a percentage that makes this program desirable and useful for as many customers as possible, and thereby incrementally more successful for customers and the state. The CMTA recommends 10%. We find this is too low. We adopt 15%, as recommended by Sun-Maid Growers of California.

Since the goal is load reduction on an entire circuit, several customers on a single circuit may file a joint binding plan guaranteeing the required curtailment on the entire circuit. We require utilities to facilitate joint curtailment plans by notifying customers of the program, and coordinating communication between customers on the circuit when any one customer expresses its intent to participate. Notification shall be performed within 21 days of this order to customers of 500 kW or more average peak demand.

SCE asks that utilities be permitted to release confidential customer information, such as customer names, to other customers on a circuit to facilitate customer communication and development of circuit-wide OBMC plans. We are not persuaded that other means are unavailable, however, and that a blanket order to release otherwise confidential information is reasonable.

For example, the notice to customers within 21 days of today may include the question whether or not the customer authorizes the release of its name, or other confidential information (e.g., average usage) to other customers on the circuit if any customer expresses interest in the OBMC. This may allow exchange of most, if not all, otherwise confidential information by the utility. Alternatively, one or more interested customers (or the utility) can arrange a meeting, and prepare an invitation. The utility can mail the invitation to all customers on an individual circuit. The utility can attend the meeting to help explain OBMC and, as we direct above, use the OBMC program to meet the needs of both its customers and the overall electric system. Therefore, because we are not persuaded that reasonable alternatives are unavailable, we decline to adopt SCE's request.

The current OBMC program requires that a customer meet the criteria for economic damage. Those criteria are over 300 kW in size, major economic damage, or danger to health and safety. At least one party recommends reducing the economic damage amount to $50,000. We are persuaded to eliminate the criteria altogether.

Any customer, or group of customers, on a circuit should be eligible to participate in OBMC. We do not seek to limit them by size, potential economic damage, or possible danger to health and safety. Our goal is to make OBMC a viable choice for as many customers as possible. Eliminating the economic damage criteria in the face of the current State of Emergency best accomplishes that goal.

Parties raise concern over measurement of the baseline. For example, it may be measured over the last 10 days, or compared to consumption one year earlier. Failure to account for conservation efforts reduces the incentive to participate, while failure to recognize reasonable growth in demand from any number of factors may similarly penalize participation.

No single baseline measure is perfect. We balance competing interests by measuring 5% increments against usage over the last 10 days. This is the most up-to-date measurement reflecting current conditions when actual system conditions otherwise require mandatory curtailments. On the other hand, we measure the 15% total required reduction against the prior year's usage for the same month, average peak. As CMTA points out, this allows for some recognition of yearly variations and does not penalize customers for near term demand reduction efforts (e.g., conservation and efficiency in response to the Governor's February 2001 request for 10 percent conservation).

We also adopt a variation of language proposed by PG&E to clarify the baseline. The baseline used to determine if the required load reduction has been obtained will be the average demand for the same period using the most recently available past 10 similar business or weekend days. This will prevent comparison of off-peak with on-peak hours, or an average of low load early morning hours with other hours.

PG&E states it intends to apply an hourly comparison. This appears reasonable. We think that the comparison may be made on an hourly basis, or over the same consistent several hour period (e.g., several hours in a Stage 3 event). The basis for the comparison, however, must be specified by OBMC participants in their circuit plan, and must be accepted by the utility.

Finally, we clarify that OBMC participants are not foreclosed from contributing load reductions during Stage 1 or 2 events through the VDRP program, but are not eligible to be paid during an OBMC event. That is, during an OBMC event, their OBMC commitment supercedes participation in any other program.

### 5.9 SDG&E HVAC Program

There is broad theoretical appeal and interest in using market-based approaches to balance supply and demand, including real time meters and real time prices. In particular, the CEC supports wide use of market-based solutions.

When markets are dysfunctional, however, there are equity and efficiency problems with this approach. Moreover, there are other unresolved problems, such as the balancing of earned revenues with the revenue requirement.

Nonetheless, there is room in our adopted portfolio of approaches addressing the current crisis for the SDG&E heating, ventilation, and air conditioning (HVAC) program, as a variation on market based solutions. As such, we adopt Energy Division's recommendation for further study of SDG&E's potentially useful HVAC program. To facilitate this further study, we will provide meters and communication equipment without charge to customers who participate in the VDRP.

### 5.10 ISO Programs

Some parties advocate Commission reliance on ISO programs. Further, some parties recommend allowing respondent utilities to act as aggregators for ISO programs. We decline to adopt these proposals. Rather, we implement close coordination with ISO programs to maximize the benefits for the State.

We authorize programs in this decision that are similar to some programs offered by the ISO, but generally at a lower price. There is no net benefit to California for similar programs competing for subscribers at different prices. Rather, to the extent a participant chooses between programs (i.e., a customer who will participate but is simply selecting one program or another), the customer will select the program that pays the higher price. That does not result in any additional load reduction, only a higher cost to ratepayers.

As a result, we decline to allow a customer enrolled in a respondent utility program from enrolling in a similar ISO program, until the customer has fully exhausted the utility program.[17] We will continue the current policy of prohibiting interruptible customers from participating in the ISO's Ancillary Services Load Program. Once the customer has exhausted the utility program, however, the customer may participate in the ISO similar program.

Customers may not opt-out of existing programs to enroll in an ISO program, or enroll in a similar new utility program. As explained above, this limitation prevents unreasonable turnover between similar programs without benefit to the state.

Where programs are different, the customer may join either the utility or ISO program without condition. For example, if the customer is in a utility capacity program, the customer may select either the utility or the ISO pay-for-performance program.

Finally, respondent utilities should spend their limited time and resources making programs adopted herein successful and fully utilized. Thus, we prohibit respondent utilities to act as aggregators for ISO programs. We will authorize the respondent utilities to act as aggregator for bids in the ISO's DRP accepted as of today.

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[17] For example, a customer enrolled in the BIP cannot simultaneously enroll in the ISO's DRP. A customer enrolled in the VDRP cannot simultaneously enroll in an ISO pay-for-performance program.

# 6. Rotating Outage Programs

## 6.1 Modifications for Equity

### 6.1.1 Study Narrowing Exempted Load by Reconfiguring Circuits

Many customers are exempt from rotating outages because they share a circuit with an essential customer. For example, PG&E has approximately 2.0 million customers who receive service on a circuit exempt from rotating outage, even though less than 1,700 are essential customers.

PG&E estimates that there are approximately 5,000 essential customers statewide subscribed to service from respondent utilities. If the same relationship applies statewide as in PG&E's service area, over 5.8 million non-essential customers are exempt from outage only because they share a circuit with an essential customer.

Inclusion of these non-essential customers in the rotating outage pool would increase the amount of load available for emergency curtailment by thousands of megawatts.[18] This could significantly reduce the frequency and duration of outages all other customers will face, and would more equitably distribute the burden of outages. Further, it would ensure that all non-essential customers experience the same incentive to voluntarily curtail use before mandatory curtailments are initiated, thereby assisting the entire State weather the current crisis.

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[18] If each of PG&E's approximately 2.0 million non-essential customers now exempt from rolling outages uses only 1 kW on average, including all these customers in the rotating outage pool would increase the pool by about 2,000 MW. If about 5.8 million non-essential customers are added to the rotating outage pool at an average of 1kW per customer, the outage pool would increase by about 5,800 MW statewide.

Therefore, we adopt the Energy Division recommendation, and order respondent utilities to study reconfiguring circuits to narrow exempted load to more nearly match only the load of essential customers. We recognize objections from respondent utilities that it will be far too costly to rewire circuits to isolate only essential customers. For example, PG&E claims it can cost between $500,000 and $1,000,000 per circuit to construct a new circuit to isolate the essential customer. Equity, and the practical need to reasonably increase the available pool to get California through this crisis, however, require that this matter be carefully studied.

PG&E suggests, for example, that a limited number of circuits might be rewired when an essential customer is located close to a sub-station by installing SCADA-controlled circuit switching devices between the essential and non-essential customers.[19] We are convinced that these and other options must be studied.

Therefore, by June 1, 2001, each respondent utility shall file and serve a report. This report (and other reports discussed below) shall be filed in this docket, and served on the service list. Except for service on the Commission, each respondent utility may serve a Notice of Availability on the service list, even if the report is less than 75 pages (unless a party has previously informed respondent utility of its desire to receive a complete copy).[20]

The report shall state the results of a study to isolate essential from non-essential customers, and increase the pool of non-essential customers available

[19] SCADA-controlled circuit switching devices are remotely controlled devices. SCADA stands for Supervisory Control and Data Acquisition (SCADA).

[20] Rule 2.3 of the Commission's Rules of Practice and Procedure.

for rotating outages by Summer 2001, Summer 2002, and beyond. The study shall list the amount of additional load added to the rotating outage pool, the time required to complete the reconfiguration, and the cost. Respondent utilities may limit the study to projects costing $500,000 or less per individual reconfiguration since we expect the study to be of the most cost-effective alternatives.

The report shall sort the list of projects in three ways: by amount of additional megawatts added to the rotating outage pool, by date the reconfiguration can be accomplished, and by cost. Each report shall include a recommendation on whether or not to implement any or all reconfigurations, and, if reconfigurations are ordered even over a respondent utility's objection, the most efficient and least costly way to proceed. If it is not possible to study all candidate circuits given limited time, the study may focus on those circuits most likely to produce cost-effective additions contributing the most additional megawatts to the rotating outage pool.

Each report shall also state the results of studying alternative means to achieve the same goal less expensively. For example, it may be less costly to assist essential customers acquire and install backup generation than reconfigure circuits to isolate the essential customer.

Each respondent utility shall implement all cost-effective, reasonable projects. If a respondent utility believes Commission authority is needed to implement a project, respondent utility may seek approval from the Energy Division Director for projects up to a cumulative total of $5 million for PG&E and SCE, and $1 million for SDG&E. The Energy Division Director shall have delegated authority to authorize cost-effective, reasonable projects to these totals. These totals shall be included in the total program limits addressed below (e.g., $200 million for PG&E, $275 for SCE, and $25 million for SDG&E). If a respondent utility believes Commission authority is needed to implement its recommendation over the cumulative totals above delegated to the Energy Division Director, respondent utility shall file and serve an application or advice letter, as appropriate, seeking such authority. Any request, however, either to the Energy Division Director or Commission, must convincingly show why Commission authorization is needed.

#### 6.1.2 Include Most Transmission Level Customers in Rotating Outages

Few customers were served at transmission voltage when the Commission first established procedures for rotating outages. As a result, adopted rotating outage procedures generally do not include transmission level customers.[21] Now, however, a significant number of large customers receive service at transmission level.

Equity between customers is compromised by treating customers differently for purposes of rotating outages based solely on service voltage. Further, limiting the pool of customers subject to rotating outages increases the likelihood of outages for those in the rotating outage pool, while the excluded customer is protected. Customers exempt from rotating outages also have less incentive to participate in interruptible or OBMC programs designed to prevent rotating outages.

Transmission level customers cite safety and financial concerns with being included in rotating outages. These are legitimate concerns, but must be put in perspective. All customers, including those at transmission level, face the risk of

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[21] SCE reports it includes transmission level customers in rotating outage pools, with the exception of essential customers.

periodic outages unrelated to supply shortages (e.g., weather, individual transmission line failures, individual transformer failures, and operational factors). Further, transmission level customers are in a better position than most to be in contact with a utility account representative, and to monitor other information sources (e.g., ISO web site), to increase their knowledge about possible outages. Transmission level customers are not unique in their responsibility to share the burden of outages, but, like many customers, may be in a position to moderate the effect.

As a result, we generally adopt Energy Division's recommendation, with some modifications. Respondent utilities shall include transmission level customers in rotating outages, subject to exclusion for essential use customers (e.g., national defense), and those participating in an OBMC program.

We also exclude transmission level customers who are supplying power to the grid in excess of their load at the time of the outage. Exclusion from rotating outages is an important and valuable benefit. In exchange, however, the transmission level customer must provide power to the grid in excess of its load at the time of the outage. Utilities shall give such customers a reasonable opportunity to become net suppliers at the time of the outage, since the customer may or may not at any particular moment be a net supplier. Failure to become a net supplier in a reasonable amount of time shall result in the customer loosing the exemption.

PG&E points out that about 75% of its transmission level customers cannot be easily curtailed without extensive interaction with, and cooperation from, the customer. We acknowledge PG&E's concern, and adopt PG&E's recommended remedy. That is, we clearly state that transmission level customers—except those who are essential use, OBMC participants, or net suppliers to the grid—must respond promptly to utility requests to drop load. If the customer refuses to cooperate, the respondent utility may install automatic switching equipment, controlled by the utility, at the customer's expense. A customer who refuses to drop load before the switch is installed shall be assessed a penalty of $6/kWh for all kWh taken off the grid. This level of penalty is consistent with the penalty adopted in the BIP and OBMC programs. The penalty will not apply if the customer's generator suffers a verifiable, and verified, forced outage. It will also not apply during times of scheduled maintenance, as long as the maintenance is scheduled with, and agreed to, by both the ISO and the serving respondent utility. The ISO and respondent utility may not unreasonably withhold agreement of the customer's proposed scheduled maintenance.

At the same time, our instructions to include transmission level customers in rotating outages is not to result in compromising the integrity of the transmission and distribution systems. Respondent utilities, in cooperation with the ISO, shall assess system integrity on a case-by-case basis before including a transmission level customer in the rotating outage pool, and shall decline to include any such customer if system integrity is jeopardized by inclusion of that customer in the rotating outage pool.

### 6.1.3 Essential Customers

Some essential customers (e.g., hospitals, prisons) are now enrolled in interruptible programs. Other customers with vital public health, safety or welfare characteristics, even if not essential customers (e.g., schools), are similarly enrolled in interruptible programs.

There may be an apparent or actual conflict with an essential or other similarly situated customer being eligible for, and enrolled in, an interruptible program. That is, a customer seemingly cannot both be essential and thereby excused from interruption, but be able to interrupt load and enjoy a rate discount.

The Commission has not previously required utilities to screen interruptible program participants. This is based on the assumption that each customer, rather than the utility, is in the best position to determine whether or not it can reasonably and responsibly interrupt some or all load upon request. For example, some customers have backup generation or other ways to participate with part or all of their load.

We partly address this apparent or actual conflict by allowing reasonable flexibility for SCE customers to opt out or change firm service level during a 15-day window. This opt-out is for both essential and non-essential customers on SCE's interruptible tariffs.

Further, however, we clarify for all respondent utilities that essential customers may participate in interruptible tariffs, but eligibility must now be screened by the utility. PG&E points out that utilities may or may not now use consistent criteria for determining whether essential customers should be exempt from rotating outages, and states that any Commission guidance or direction would be helpful. (February 26, 2001 Reply Comments, page 8.)

To provide this guidance, we direct that utilities discuss with each present and future essential customer enrolled in an interruptible program whether or not that customer is reasonably eligible for an interruptible program. The customer should demonstrate, for example, sufficient backup generation or other means to meet its essential load if interrupted.

This demonstration and screening may be accomplished by respondent utilities requiring a declaration under penalty of perjury from the customer. The declaration must state that the customer is, to the best of that customer's understanding, an essential customer under Commission rules and exempt from rotating outages. It must also state that the customer voluntarily elects to participate in an interruptible program for part or all of its load based on adequate backup generation or other means to interrupt load upon request by respondent utility, while continuing to meet its essential needs. Absent such declaration, respondent utilities may find the essential customer ineligible to participate in one or more interruptible tariffs.

We are further persuaded to limit the amount of load an essential customer may commit to interruptible programs to no more than 50% of the customer's average peak load. We seek to prevent an essential customer from committing more than it reasonably can, even if it has good intentions to help California through the current difficulties. Essential customers have special needs and responsibilities to the State. This limitation will better balance some contribution by an essential customer to interruptible programs (when it is feasible for the customer to do so) with the customer's essential status.

#### 6.1.4 Fossil Fuel Producers

Electric utility facilities are currently exempt from rotating outages, along with supporting fuel and fuel transportation systems (e.g., pipelines) critical to the continuity of the electric power system. (See Attachment B.) This exemption applies only to fuel needed for electric generation and does not apply to fuel used in motor vehicles or for other purposes. The CEC has responsibility to coordinate state actions regarding motor vehicle fuel usage. In response to a request from the CEC we recently granted limited wavier of penalties for two utility pipeline companies transporting the majority of California's gasoline and diesel fuel. This was in response to a recommendation from the CEC based on a threat to public health and safety. Public health and safety were at risk due to the effect on the availability and price of all petroleum products as a result of recent curtailments of electricity under interruptible programs.

We encourage the CEC to continue its vital oversight and regulatory role with respect to fossil fuel producers so that outages and interruptions can be coordinated to minimize disruptions. The ability of many fossil fuel producers to either participate in the OBMC program or utilize the exemption from outages for net electricity producers[22] should address much of the CEC's concerns. Fossil Fuel producers might reasonably be on an interruptible electricity tariff (e.g., based on backup generation), but outages must be reasonably coordinated between producers and pipelines transporting the final product to ensure that no unacceptable jeopardy occurs to public health and safety. For example, it was the voluntary participation of pipelines in utility interruptible programs that contributed to the tight supply situation that concerned the CEC.

We invite the CEC to report to us on any changes needed in our interruptible tariffs or curtailment priorities to further protect public health and safety. Finally, we authorize utilities to coordinate interruptions, to the extent feasible, between fossil fuel producers, pipelines and users to minimize any disruption to public health and safety. For example, if a refinery, oil pipeline, and bulk distribution terminal are in three different outage blocks, then the integrated fossil fuel system might be disrupted for an extended period of time. If, instead all three entities are in the same outage block, then outages can be coordinated and down time minimized. In this way, fossil fuel producers can

[22] For example, many refineries and enhanced oil recovery facilities have associated cogeneration facilities.

continue to provide needed fossil fuels while playing their part in helping maintain reliability of the electric system.

#### 6.1.5 SCADA and Non-SCADA

Implementing rotating outages by blocks allows circuits to be curtailed widely throughout a service area, and not solely by geographic zones or substations. Circuits are controlled either remotely (SCADA) or manually (non-SCADA). Manually controlled circuits must be disengaged by substation personnel to implement a controlled curtailment. The need for manual operation increases the time to implement a curtailment. This, in turn, affects the total amount of load that may be curtailed in any particular period.

PG&E has an especially large service territory with many unstaffed substations. The ISO may give very short notice (e.g., 10 minutes) of a Stage 3 mandatory curtailment. As a result, Energy Division recommends that PG&E be ordered to assign staff up to 24 hours per day at all potentially affected substations when a Stage 2 alert is declared in order to be ready to implement a Stage 3 rolling outage.

PG&E objects, pointing out that it has successfully included both remotely and manually controlled circuits in each rotating outage over the last eight months. PG&E states that it has dispatched personnel as needed to substations with adequate lead time to ensure interruptions were completed consistent with ISO orders. PG&E says its approach is equitable to customers on both SCADA and non-SCADA controlled circuits, and provides for rapid response. According to PG&E, ordering potentially thousands of hours of staff time to non-SCADA substations is unsupportable. SCE states that SCE's approach to automated and manual substations is equally efficient and equitable.

SDG&E reports that its current Stage 3 curtailment plan is designed almost entirely around the use of SCADA controlled 12 kV circuits, but that it will attempt to add a proportional mix of non-SCADA circuits for Summer 2001 to promote increased equity. (February 22, 2001 Comments, page 20.) SDG&E asserts that the use of SCADA-controlled circuits remains preferable, however, given the short amount of time to respond to an ISO curtailment order, and the cost of assigning personnel to non-SCADA substations. It is also preferable, according to SDG&E, because use of non-SCADA circuits cause additional complications for its Distribution Operations Department, and additional time to execute the customer call process to warn customers of outages. SDG&E urges Commission consideration of cost and efficiency as well as equity.

We are persuaded that respondent utilities are now treating, or plan to treat, customers on SCADA and non-SCADA circuits with reasonable efficiency and equity, but believe improvements can be made. The issue is of sufficient importance to cost, efficiency and equity that we encourage continued study by respondent utilities.

In particular, the current best forecast is that rotating outages will become a common occurrence in Summer 2001, and may also be common in Summer 2002. If so, it is imperative that all reasonable steps have been studied and undertaken to ensure equitable implementation of forced outages that are efficient and within reasonable cost.

Therefore, we direct each respondent utility to file and serve a report by June 1, 2001. The report shall state the cost of dispatching personnel versus installing automated equipment in remote locations to implement forced outages. The cost study may be based on a reasonable sample of manually controlled substations. Each report shall state any changes each respondent utility has made, or is making, to promote increased efficiency and equity, and the costs of those changes. If respondent utility believes Commission authority is needed before it can implement changes, respondent utility shall file and serve an application or advice letter, as appropriate, seeking such authority.

### 6.1.6 Notification Regarding Reclassifications

By ACR dated March 27, 2001, Assigned Commissioner Wood ordered respondent utilities to provide written notice to customers regarding reclassifications between essential and non-essential categories. (See Attachment E.) We approve and confirm the ruling. (Pub. Util. Code Section 310.)

The ACR requires respondent utilities to provide written notice of the reclassification to any customer reclassified between June 1, 2000 and the date of notice, with the notice served within 15 days of the date of the ACR. Further, before implementing any future reclassification, utilities must provide advance written notice to the customer, with the reclassification effective no sooner than 15 days after the date of notice.

The notice must explain the Commission's priority system, how the system is implemented by the utility, and include excerpts from relevant Commission decisions. It must advise the customer that questions regarding the reclassification should first be discussed with the utility within 15 days of the date of notice. It must state that, absent written objection served on the utility within 15 days of the date of the notice, the reclassification shall be considered undisputed.

Further, the notice must state that unresolved disputes may be brought to the Commission by customer-filed complaint. The notice is also required to state that a complaint brought to the Commission must allege and show that the utility has acted or failed to act in violation of law, or in violation of any order or rule of the Commission, by the utility improperly implementing, or failing to follow, the Commission's adopted priority system. The burden is then on the utility to defend its implementation and reclassification.

The ACR is reasonable. Utilities review customer classification as necessary, including as part of each annual action plan. Necessary customer reclassification based on updated or new information has always been important, but was of less consequence when the probability of rotating outages was small. The consequences of reclassification, however, can now be great, given the experience of rotating outages in 2000 and 2001, and the increased likelihood of rotating outages through the rest of 2001 and possibly beyond.

Respondent utilities have reclassified many customers within the last year as part of ongoing reviews, and annual action plan updates. Individual customer notice was not provided. Coverage in the news media and elsewhere, however, has resulted in both customer confusion, and questions regarding whether or not the reclassifications comply with Commission orders.

Each reclassified customer deserves the right to be notified of an important change affecting service. Each reclassified customer has the right to question an important change to ensure that the change complies with law, as well as Commission rules and orders. Each reclassified customer has the right to file a complaint if the customer believes the change is in error.

We agree with the ACR that notice is required only on the customer who is reclassified, not on each customer whose service was, or is, changed because it shares a circuit with a reclassified customer. Wider notice is not required because circuits may be reclassified at any time for any number of operational reasons. For example, an essential customer might be transferred from one circuit to another due to operational factors, with resulting effects on all other customers on the two circuits. The only customer with standing to address the reclassification, however, is the customer whose status is reclassified between essential and non-essential, not each customer whose service changes as a consequence.

Further, we agree with the ACR that the utility is not required to automatically reverse the reclassification of any customer upon customer complaint to the utility, but may reverse the reclassification if the customer presents sufficient evidence to convince the utility to do so. The utility shall, however, reverse the reclassification upon direction from the Commission staff or the Commission if the customer files a complaint with the Commission, and the complaint is resolved either informally or formally.

In addition, we also concur with the ACR that the burden shifts to the utility to defend its implementation and reclassification upon the filing of a complaint with the Commission that reasonably alleges the utility has acted or failed to act in violation of law, or in violation of any order or rule of the Commission, by the utility improperly implementing, or failing to follow, the Commission's adopted priority system. These complaints will be proceeded using the Commission's expedited complaint procedure.

### 6.2 Modifications to Increase Protection

#### 6.2.1 Outbound Calling Program

PG&E provides electric service to approximately 48,000 medical baseline customers,[23] of whom about 22,000 are classified as "life support" customers. Life support customers require electrical equipment to sustain, restore or supplant a vital body function. SCE reports that it has about 27, 000 medical baseline customers, of whom about 2,200 are critical care customers. SDG&E has a similar distribution of such customers.

[23] This is about 1.2% of PG&E's total residential service customers.

Neither medical baseline, nor life support, nor critical care customers, however, are defined as essential customers under Commission rules. As with all other customers, respondent utilities are simply required to provide warning and relevant information by mass media, with no special treatment or individual notification required. (See Attachment B.)

Because of the vital role of electricity for these customers, Energy Division recommends that respondent utilities inspect backup generation or battery supplies for life-support equipment. We decline to adopt this recommendation. Rather, we are persuaded by respondent utilities that this would be a difficult task involving expertise that each utility does not necessarily now have. In fact, as SCE says, it could even be dangerous for the utility to certify the functioning of equipment which is designed for special medical uses and which is owned, operated and maintained by the customer or others. As SDG&E states, the logistics of annual or more frequent inspections could be staggering, particularly as the population of customers on life support changes. Further, liability could attach to each utility for injury and death that would be unreasonable under current circumstances. That is, existing infrastructure exists in the medical community and industry to supply and inspect backup devices for vital medical equipment, and we need not order utilities to duplicate that infrastructure.

Energy Division also recommends that respondent utilities be required to notify customers on life support by telephone of rotating outages. In response, utilities report that they have such systems. PG&E has an automated voice response system that initiates outbound calls to all life support customers potentially impacted by rotating outages. (February 22, 2001 Comments, page 17.) SCE has a procedure in place to initiate an automatically dialed call to all medical baseline customers, targeting critical care customers first. (February 22, 2001 Comments, page 34.) SDG&E reports that it has contacted life support customers by telephone and live agent prior to every imminent Stage 3 rotating outage and, immediately after restoration of electricity, plans to call customers on life support and medical baseline to ensure that electric service has been reactivated. (February 22, 2001 Comments, page 24.) We are encouraged by these responses.

Few actual rotating outages were implemented during more than 30 days of continuous Stage 3 emergencies in early 2001.[24] We are sympathetic to respondent utilities' concerns about the number of false calls if calls are required for all Stage 3 events. Thus, we direct that the outbound call be made only when a rotating outage is imminent. While we consider this outbound calling program important, we continue to require only that respondent utilities undertake best efforts to notify customers of imminent outages.

Further, improvements in technology may be available to shorten the time between ISO notice to the utility, and utility notice to the customer. We understand SCE can complete the required notification within 10 minutes. We expect respondent utilities to not only establish systems to achieve notice quickly, but to use the best available technology to reduce the time required to execute reasonable notice. We encourage utilities to use automated, recorded messages where not now used, when it is reasonable and efficient to do so. We also urge utilities to explore advanced technologies to increase the number of customers who may be notified in advance of an event, reduce the time to achieve reasonable notice, and reduce long run cost.

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[24] Stage 3 emergencies were called by the ISO from January 15, 2001 through February 15, 2001.

To inform the Commission and the public, each respondent utility shall file and serve a report by June 1, 2001. The report shall describe each utility's outbound calling program to customers on life support, critical care or medical baseline when a rotating outage is imminent. The document shall report on the implemented program, including any changes made or planned, to improve the program. If respondent utility believes Commission authority is needed before it can implement such program or changes consistent with this order, respondent utility shall file and serve an application or advice letter, as appropriate, seeking such authority.

This program is not intended to replace utility programs for periodic notification by mail to medical baseline customers of the need to have backup resources or plans for electrical outages. We also consider this a vital piece of communication. We endorse utilities continuing this notification by mail, or expanded to mass media, as often as necessary and reasonable.

#### 6.2.2 Offices of Emergency Services

Electric service to industrial customers may be especially critical to public health and safety. For example, public health and safety may be at increased risk if the curtailment of electricity to an industrial customer causes equipment causes the release of chemicals or toxins.

We have confidence in the efforts of national and state offices of Occupational Safety and Health Administration (OSHA), and regional Offices of Emergency Services (OES). We support these and other government agencies working with electricity customers and electric utilities to ensure all reasonable steps are taken to protect public health and safety during probable forthcoming electrical outages in Summer 2001 and Summer 2002.

To assure ourselves and the public that reasonable efforts are undertaken, we direct each respondent utility to file and serve a report by June 1, 2001. The document shall report on any recent efforts undertaken by respondent utility with OSHA and/or OES to address particular and unique risks to public health and safety from imminent electrical outages to industrial customers in Summer 2001. In particular, each report shall identify any measures that have been implemented for one or more industrial customers required for public health and safety after the customer and/or respondent utility consults with OSHA and/or OES.

#### 6.2.3 BART and MUNI

Rotating electrical outages may cause particular concern for public health and safety when they involve underground transit systems, such as the Bay Area Rapid Transit District (BART), and the San Francisco Municipal Railway (MUNI). Energy Division recommends an exemption from rotating outages for BART, and implementation of mitigation measures to ensure safety of MUNI passengers and staff.

PG&E states that it is technically feasible to exempt BART from rotating outages without significant negative effects on its overall emergency response plan, and that such exemption is in place. PG&E asks that the underground component of MUNI be similarly exempt. We authorize PG&E to exempt both BART, and the underground portion of MUNI, from rotating outages.

PG&E reports that it supports adequate mitigation measures to protect MUNI passengers and staff. PG&E asks, however, that it not be placed in the position of determining what is and is not adequate mitigation. Rather, PG&E asks that the Commission review requests for exemption by public transportation providers, and provide necessary direction to utilities.

We will give direction as necessary, but this record does not contain adequate information to do more than we do here. We are confident, however, that PG&E can, and will, work out necessary and reasonable mitigation with MUNI.

To provide reasonable information to the Commission and the public that this is accomplished, and provide a vehicle to resolve disputes, PG&E shall file and serve a report by May 1, 2001 on this matter. The report shall state the necessary and reasonable mitigation measures to which PG&E and MUNI have agreed, and the measures that PG&E has, or will, implement. MUNI may file a complaint if unresolved disputes remain.

If PG&E believes Commission authority is needed before it can implement mitigation measures for MUNI, PG&E shall file and serve an application or advice letter, as appropriate, seeking such authority. If the application or advice letter is supported by MUNI, PG&E shall seek to expedite matters by including a statement from MUNI in partial or full support of the request.

#### 6.2.4 Other Rail Transit

Energy Division recommends that other rail transit systems participate in this rulemaking for the purpose of presenting a joint proposal with utilities to implement other necessary mitigation measures, or seek complete exemption from rotating outages.

We note that no other transit system has brought any concerns to our attention. SDG&E points out that the San Diego Trolley is entirely above ground. It is served by a large number of different circuits. Exempting the entire Trolley system would exempt a large number of circuits from rolling outages, and reduce SDG&E's ability to implement forced outages.

Nonetheless, because of the potential importance of this issue to public health and safety, we direct the Executive Director to serve a copy of this decision on other rail transit systems under our jurisdiction.[25] The cover letter shall invite those transit systems to consider public health and safety on their systems due to the serious potential of a number of electrical outages in 2001 and 2002. It will recommend that each system discuss the matter with their serving utility, and cooperatively implement any reasonable and necessary mitigation measures. It shall also invite each system to make a joint proposal, in cooperation with its serving utility, other rail systems, and the Rail Safety and Carrier Division, regarding any mitigation measures that should be considered by the Commission, and which require Commission authorization.

### 6.2.5 Utility Outage Notification Plans

Energy Division recommends that respondent utilities implement rotating outage notification plans that are more accessible, and expand these plans to include customers with special needs. Energy Division also recommends that press release notifications should be multilingual, outgoing notifications should be implemented for all essential customers, and the adequacy of inbound calls and procedures be reassessed given likely call volumes during outages.

Respondent utilities generally report adequate multilingual notification procedures, and reasonable outbound and inbound calling capabilities. All three utilities are unclear regarding the definition of "special needs" groups and ask for clarification before the Commission imposes additional burdens and costs.

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[25] Muni (through the City and County of San Francisco) and BART are each already parties to this proceeding. The decision should be served on Los Angeles County Metropolitan Transit Authority, Sacramento Regional Transit District, Santa Clara Valley Transportation Authority, and San Diego Trolley Incorporated.

We are generally satisfied with current notification plans. We will study notification needs of special customers further in Phase 2. We especially invite any special needs customers to come forward and make their needs known.

PG&E includes a rotating outage block number on customer bills, with a note stating: "rotating outage blocks are subject to change without advance notice due to operational conditions." Neither SCE nor SDG&E notify their customers of the rotating outage block to which the customer is assigned. SCE points out that rotating outage blocks can change frequently as loads are transferred between circuits and substations to balance load, and ensure that circuits do not exceed 550 amps.

We will study further in Phase 2 the desirability and reasonableness of SCE and SDG&E including a rotating outage block number on customer bills. Rotating outage experiences in 2001 and 2002 are unlikely to be pleasant. Customers need and expect reasonable, timely and accurate information. Public health and safety may depend upon it.

We think it reasonable to give customers fair warning when their electricity is about to be curtailed, with as much specificity as possible. Rotating outage block numbers on customer bills meets that objective. It allows the utility to alert mass media so that affected customers get reasonably specific, accurate, and timely warning.

We direct SCE and SDG&E, and invite other parties, to address in Phase 2 the need, desirability and reasonableness of SCE and SDG&E including a rotating outage block number on each customer bill, with a notice that the block may change without notice based on operational conditions. Parties shall include this issue in Phase 2 pleadings regarding a list of issues for consideration, along with their recommendations on how and when this issue should be considered.

### 6.2.6 Hospitals

The Regional Council of Rural Counties (RCRC) asks that rural hospitals and acute care facilities be classified essential customers, and excluded from rotating outages.[26] RCRC points out that hospitals with 100 beds or more are exempt from rotating outages,[27] but that the majority of rural hospitals are less than 100 beds. RCRC provides a list of counties and hospitals showing that 16 of 28 counties do not have a hospital with more than 100 beds, and would therefore be subject to rolling outages.

We must balance the need to have as many circuits available for rotating outage as possible against the need to protect essential customers. We are persuaded to modify the essential customer list to include all hospitals. Sick or injured people in rural hospitals can be just as sick or injured as their urban counterparts. They deserve the same level of protection for electricity services.

At the same time, we have little specific information on the effect of this change. We order this change because we are persuaded by the limited information we now have that rural hospitals have an immediate need for protection during the crisis we face for Summer 2001. We will revisit this issue in Phase 2, however. We direct that respondent utilities submit specific information in Phase 2 on the effect this change has had on mandatory curtailments, and the effect on the number of circuits and megawatts that are available for rotating outage. Further, the study ordered above regarding the

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[26] The RCRC represents 28 rural counties in California, which RCRC says are mostly in the PG&E service area.

[27] D.91548, Appendix B. Also see Attachment B to this order.

reconfiguration of circuits to narrow exempted load should include an assessment of isolating the rural hospitals added here.

By ACR dated March 23, 2001, Assigned Commissioner Wood partially granted emergency motions filed by Memorial Health Services and Catholic Healthcare West. (See Attachment F.) We approve and confirm the ruling. (Pub. Util. Code Section 310.)

The ruling required PG&E and SCE to immediately classify all hospitals with 100 beds or more as essential customers exempt from rotating outages, regardless of the status of backup or standby generation. The ruling found this to be consistent with the priority system for rotating outages adopted in D.91584. It cited the Commission's definition of minimal essential uses for hospitals. It found the uncontroverted testimony presented at hearing demonstrated that the backup or standby generation required by Office of Statewide Health Planning and Development regulation does not satisfy Commission requirements for minimal essential uses for hospitals. Further, it found that the exemption would not disturb or compromise the Commission's determination to maintain at least 40% of available load for rotating outages. In addition, the ruling declined to extend the exemption to skilled nursing facilities, absent a showing of the effect on maintaining at least 40% of available load for rotating outages.

The ruling is reasonable. Moreover, consistent with our modification above, all hospitals in the service areas of PG&E, SCE and SDG&E shall be classified as essential customers exempt from rotating outages, regardless of the status of backup or standby generation.

This decision, however, does not disturb utility evaluation of the adequacy of backup or standby generation for other essential customers, and utility consideration of removing such customers from their lists of essential use customers. (D.82-06-021 (June 2, 1982), Cal. PUC LEXIS 537.) Also, absent more information, it does not extend to skilled nursing facilities.

We direct respondent utilities to provide specific information no later than in Phase 2 on the effect of extending this exemption to skilled nursing facilities, including the number of circuits and megawatts removed from rotating outages. The evaluation will include an estimate of the resulting effect, if any, on mandatory curtailments, and the 40% criterion. Finally, respondent utilities must also consider circuit reconfigurations in Phase 2 that would narrow exempted load by isolating skilled nursing facilities.

### 6.3 Update Utility Action Plans

By June 30 each year, respondent utilities file annual rotating outage action plans, with verification of their essential customer list. (Energy Division Report, page 68.) The changes we order herein, and the need to ensure updated plans are in place and consistent with these orders, require that these action plans be updated and filed more quickly. Therefore, respondent utilities shall implement changes consistent with the orders herein, and file updated action plans within 45 days of the date this order is served.

## 7. Other Issues

We briefly address other recommendations which we do not adopt at this time.

### 7.1 Customer Recognition Program

Energy Division recommends a program to recognize and thank all residential and local government customers who reduce load by at least 7% in Summer 2001 compared to Summer 2000. Such customers would be recognized as energy savers. Customers maintaining that level of energy reduction for at least two consecutive months (May to October) would receive a certificate of appreciation from the Governor, and be included in a list of energy savers on a web page maintained by the Commission.

Respondent utilities express their willingness to implement this program, but raise legitimate concerns. For example, no cost-effective technology currently exists to accurately measure voluntary load reductions for the proposed recognition program. Measurement of load reductions would be difficult, with annual usage varying up to 15% based on many factors (e.g., changes in number of family members, changes in work or school hours, temperature fluctuations). Procedures to normalize consumption data may be adopted, but time is limited to develop, test and implement a procedure for mass screening of consumption data over two years for millions of customers.

Neither costs nor benefits for this program are clear. Costs for the printing and mailing of potentially millions of certificates alone could be significant. Questions of confidentiality are unanswered, particularly regarding the list of customer names on a web page maintained by the Commission. Little public support has been expressed for this program. As a result, we think limited resources available to the Commission, respondent utilities, parties, and the State are better spent on other programs.

### 7.2 Exempting Water and Sewer Districts, and Ancillary Government Services

The Association of California Water Agencies (ACWA), and several individual water districts, request Commission revision of existing essential customer regulations so that water services essential to public health, safety and welfare are exempted from rotating outages. They point out that current regulations allow water and sewer utilities to request partial or complete exemption from rotating outages in times of emergency requiring their services, such as fire fighting. They allege that the exemption is too limited, however, and point out that emergency response by the utility may not be immediate.

In particular, Santa Margarita Water District (SMWD) points out that disruption of sanitary sewage treatment and disposal systems resulting from rolling blackouts would almost certainly result in sewage spills, thereby endangering public health and safety. Moreover, SMWD says loss of electricity creates the danger of losing water system pressure, thereby providing the potential for contaminants to enter the water system. The Health Department requires bacteriological testing whenever pressure is lost in a pipeline, according to SMWD. SMWD says these tests take up to 48 hours, so that a blackout of two hours may result in disruption of water service for two days.

We appreciate these matters being brought to our attention. We received requests for modifications to our essential customer list from many customers. There is virtually no customer without some good argument for the essential nature of their use of electricity.

Expanding the list of essential customers, however, must be balanced with the detrimental effect this has on all non-essential customers (e.g., by increasing the potential frequency and duration of rotating outages for a smaller pool of non-essential customers). In PG&E's case, for example, there are approximately 1,000 circuits that would be impacted by categorically exempting this class of customer from rotating outages. This would cause a significant increase in the potential frequency and length of rotating outages absorbed by all other customers on non-essential circuits.

In this case, we find that water and sewage treatment utilities generally have backup generation or other capacity for operation and storage during power interruption. Rotating outages have not historically been a primary cause of power interruptions. Nonetheless, water and sewer utilities have properly and reasonably prepared for power interruptions due to a number of causes.

ACWA and others caution against reliance on standby generation since its capacity may be limited or unreliable. We recognize there may be limitations. In balancing the many competing interests before us, however, we must rely on water utilities installing and maintaining adequate backup generation and other facilities to permit continued operations during reasonable periods of electricity shortages. These shortages may occur from any number of causes, including weather, equipment failures, or the currently dysfunctional market. We are confident that water and sewer utilities have taken these many contingencies into account.

Further, our existing rules allow water and sewer utilities to request partial or complete rotating outage exemption, or partial or complete service restoration, based on an emergency. We are confident that water and sewer utilities can, and will, communicate clearly with respondent utilities about emergencies, and that respondent utilities will respond properly in the face of an emergency. We recognize the essential nature of water and sewer utilities, but we presently have insufficient evidence to justify expansion or modification of the exemption to which they are currently eligible.

ISD/LAC supports the limited review mechanism that would allow some customers out of interruptible programs when their load significantly affects the public health, safety and welfare. (Energy Division Report, page 47.) ISD/LAC urges that essential support agencies (e.g., data processing, courts) also be considered when considering the public health, safety and welfare role of hospitals and jails.

We decline to adopt the review mechanism.[28] We also decline to specifically include support service agencies in our list of essential customers. On balance, without very compelling reasons to the contrary, we need to increase, not decrease, the number of circuits available to absorb mandatory curtailments. In Phase 2, we will consider including jails along with prisons in our essential customer category, and other reclassifications parties may recommend, if sufficient evidence is presented to justify such reclassifications.

### 7.3 Continue Networks as Essential Customers

We currently authorize essential customer status to areas served by networks, at the discretion of the utility.[29] PG&E operates networks in downtown San Francisco and Oakland, involving approximately 20,000 customers and 400 MW.[30]

Energy Division recommends that the feasibility of including networks in rotating outages be studied, particularly given advances in technology. PG&E argues that network service should continue to be excluded from rotating outages.

We are persuaded by PG&E to continue to exempt network services, at the discretion of the utility. PG&E does not currently have the capability to isolate a

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[28] We reject the review mechanism, and adopt an expanded opportunity for all customers to opt-out or realign firm service levels. (See Section above on opt-out and realignment of firm service level.)

[29] Networks have current flowing from multiple transformers simultaneously, with secondary networks found in some dense urban areas. Networks exist in limited areas to improve local system reliability. (Energy Division Report, page 71.)

[30] SCE reports that it does not exempt networked systems from rotating outages in its service area. (February 22, 2001 Comments, page 28.)

portion of the network. We expect PG&E to study this, however, as a part of the study that it will conduct on isolating essential customers. We do not, however, order any other or further assessment of including networks as a whole in rotating outages.

### 7.4 Advance Notification

Several parties ask that they be given more than 30 minutes notice before an outage. Some interruptible program proposals are linked to more or less notice.

We decline to order any more notice than respondent utilities are able to now give. The ISO determines when an outage is required, how much, and where. We are persuaded by respondent utilities that they provide as much notice as they can, given the amount of notice they receive from the ISO.

Increasing the notice of an outage increases the uncertainty of the needed curtailment amount. That is, a shortage forecast one-day ahead will necessarily have a larger range of error than a shortage forecast made one hour, or 10 minutes ahead. There is clearly a trade-off between the accuracy of the needed curtailment and the amount of notice.

We will not order the ISO to change its practices. Nonetheless, we recommend that the ISO and utilities study this matter further.

In particular, we direct respondent utilities to study and report on methods and systems they might use to provide more advance notice to customers of likely rotating outages. For example, every morning that outages are likely utilities might use mass media to announce the sequence of block numbers expected to be subject to rotating outages that day, with approximate times. In addition, every morning each utility might post this information on its web site, or other easily accessible site.

Each respondent utility should file and serve this report by May 1, 2001. The document should report on existing methods and systems used by each respondent utility, and any new methods or systems each utility has, or will, implement for Summer 2001.

### 7.5 Scheduled Load Reduction Program

Joint parties recommend a Scheduled Load Reduction Program (SLRP). (Item II.B.4 in the February 14, 2001 Joint Proposal.) In this program, a participant identifies a specific 2 to 4 hour period, one or two times per week, coincident with ISO-determined morning or evening system peak conditions, when the participant agrees to drop a preset amount of load. The participant would be under a standing order to curtail such load during these times.

We decline to adopt the SLRP for three reasons. First, program benefits are uncertain given no guarantee that load reductions will be needed at scheduled times. As noted above, the further away the forecast of need from actual operating conditions, the larger the likely range of error between scheduled reductions and actual need.

Second, scheduled load reductions may be offset by load shifts to another time. Joint parties state that program compliance would require a participant not shift load to another day, or to a peak load hour when there is no curtailment. No measures are proposed to implement this condition, however, and we are not persuaded that reasonable measurement of, and enforcement against, load shifting can be developed in the short time we have to implement programs for Summer 2001. Some, if not most, participants would feel great pressure to shift load to meet production schedules, or meet other business obligations. There would be an inherent conflict built into this program that is not sufficiently well understood to provide reasonable confidence of program success.

Third, we are uncertain about program cost-effectiveness. Joint parties say that the Commission may determine the per kWh incentives before beginning the program. No specific proposals are made, however. Assuming the payments are made all year, the program may be very expensive for little load reduction coincident with need. Program participation is unknown at moderate price levels reflecting this uncertainty. Other pricing options are not sufficiently developed to evaluate. We think participants in the SLRP are good candidates for the VDRP, and that the VDRP better matches participation with need.

We welcome all creative proposals to help us through Summer 2001 and beyond. We decline, however, to spend the limited time and resources of parties and the Commission to further develop the SLRP given the immediate need to authorize and implement programs for Summer 2001, and given other more promising programs, such as the VDRP. Parties might further develop the SLRP for later consideration and adoption.

Several parties commenting on the DD recommend reversal of the decision to not adopt SLRP. Parties point out, for example, that time of use of interval meters may be used to measure load shifts, with penalties attached as necessary for those shifts. Parties assert that everything must be done to address probable Summer 2001 shortages, and SLRP is one tool of many that should be adopted.

We are not convinced. The SLRP is not yet sufficiently well developed by parties to adopt. We must balance adopting anything and everything proposed that might possibly help, with programs that are most likely to be cost-effective and successful.

We encourage parties to continue to work on the SLRP, and bring back a more developed proposal, including measurement of load shifts, prices for participation, and penalties for load shifts. The proposal may be made by petition for modification presented before Summer 2001, or in Phase 2. While a single party may make such proposal, the most convincing proposal would be one subscribed to by as many parties as possible. Thus, we encourage interested parties to coordinate development of a proposal to the extent feasible.

### 7.6 Other Recommendations

We carefully considered all other topics, recommendations and arguments raised by parties, but are not persuaded to make any other changes for Summer 2001.

## 8. Funding and Program Limits

We are convinced by parties that we must address funding. We are also convinced that we must establish limits so that the cost of interruptible programs and new curtailment priorities do not get outside just and reasonable bounds, potentially causing harm to public health, safety and welfare similar to that which is now caused by the dysfunctional wholesale market itself.

### 8.1 Funding

Much of what we authorize today can be accomplished within existing rates and sources of funds. For example, adopted improvements to existing tariffs require no new rates or funds. Similarly, no new rates or funds are needed for extending current programs to December 31, 2002, requiring a declaration regarding insurance, lifting penalties for non-compliance, and reopening SCE's existing air conditioner cycling program.

Moreover, customers electing to opt out of SCE's program will increase SCE's sources of funds. This will occur to the extent some customers return part or all of their interruptible load to firm service. This already occurred for PG&E when 124 MW (20%) of its interruptible customers left the program in November 2000.

Further, many other changes we make today do not require an overall increase in rates, or new funds from all customers. For example, no new rate design or new funds are required to include most transmission customers in rotating outages (e.g., individual customers will fund installation of automatic switching for non-compliance). Similarly, no new rates or funds are needed to require a declaration from essential customers before they may participate in an interruptible program; require utilities to coordinate outages where feasible for fossil fuel producers, pipelines and users; and exempt BART and underground MUNI operations from rotating outages.

Some programs, however, may require new sources of money. For example, new funds may be needed for the new BIP, VDRP, SCE's new air conditioner cycling program, and new meters. Additional funds not now available from existing rates may be needed for utility implementation of OBMC programs, required studies (e.g., reconfiguring circuits to narrow exempted load), and outbound calling programs for PG&E and SDG&E.

We consider three possible sources of funds proposed by parties, including the one recommended by Joint Parties. These are: ISO rate, respondent utility surcharge, and DWR procurement rate. We also consider a utility memorandum account.

First, some parties suggest that all program costs be included in ISO rates and charges. We decline to pursue this option. ISO rates are set by FERC, which may or may not allow such charges. ISO revenues are dependent upon funds from respondent utilities. Those funds, at least in the viewpoint of some parties, are currently uncertain. Further, ISO rates and charges may affect municipal utilities. We are told by the ISO that municipal utilities are likely to resist such funding.

Second, we may increase respondent utility rates by a surcharge. We will not do this given the current rate freeze. That is, as we recently said in D.01-03-073, we cannot raise electric utility rates until we have determined that the rate freeze is over, or unless the Legislature specifically authorizes us to impose an additional charge during the freeze to recover these costs. We recognize that SDG&E's rate freeze is over, although there is a rate cap on SDG&E's generation-related rate component. However, SDG&E is also subject to performance-based ratemaking (PBR) for its distribution revenue requirement. It would be inconsistent with the PBR framework to address the level of SDG&E's distribution revenue requirement and rates on a piecemeal basis. Instead, SDG&E may address the costs of these programs within the context of the PBR mechanism in its next PBR and cost-of-service proceeding, and, if reasonable, the Commission may consider the matter further there.

Moreover, we note that we recently raised rates for PG&E and SCE above currently controlled levels by approximately $2.5 billion annually. (D.01-03-082.) We decline to raise rates again here on a piecemeal basis until we have further opportunity to assess the effects and uses of those funds.

Third, Joint Parties recommend that program costs:

> "be charged against amounts collected by the UDC [utility distribution company] on behalf of the Department of Water Resources for power supplied by that department to the customers of the electrical corporation." (February 14, 2001 Joint Proposal, page 5.)

We appreciate this creative recommendation. Under current circumstances, however, this option is not available.

At the request of the Administrative Law Judge, PG&E explained how this proposal would work. (February 22, 2001 Comments, page 2.) According to PG&E, if DWR's total revenues from customers for some period is $200 million, and interruptible program costs are $13 million, DWR's net revenue would be $187 million. Apparently, however, there are many details of this proposal that are unspecified and would have to be worked out.

Under current legislation, DWR establishes its own revenue requirement at what DWR determines to be just and reasonable levels.[31] It is unlikely that DWR will accept a discount from total revenues to cover the cost of utility interruptible programs.[32] Further, there are questions about DWR or Commission authority to reflect utility interruptible program costs in DWR's revenue requirement, or to impose a higher DWR revenue requirement on utilities.[33] These issues need further examination.

The fourth option is to authorize respondent utilities to track program costs in a memorandum account for future recovery. That recovery might be in ISO, DWR or utility rates, or some other source of funds. Legislation may soon authorize recovery of these funds from any number of sources. This is the option we will adopt.

The balance in each memorandum account may include all dollars each respondent utility believes it has spent or received above funds authorized in current rates to implement any decision in today's order. The accounting must

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[31] AB X1, February 1, 2001; Pub. Util. Code §§ 355.1, 360.5, and 366.5; Division 27 (commencing with Section 80000) of the Water Code.

[32] Using PG&E's example, if DWR sets its revenue requirement at $200 million, there is no reason to believe that DWR will accept $187 million.

[33] Again using PG&E's example, it is unclear whether a $200 million DWR just and reasonable revenue requirement might be made $213 million by DWR or the Commission.

separately identify the basis for each cost or revenue (e.g., separately track costs from the new BIP, VDRP, SCE's new air conditioner cycling program, each curtailment study; separately track revenues from penalties or other sources related to BIP, VDRP, OBMC; separately track incremental firm service revenues from customers who elect to opt our or change from service level). Utilities may include interest on the balance in each memorandum account.

The burden to demonstrate reasonableness for cost recovery will be on each respondent utility, but the bar will be low. That is, we are in a State of Emergency. We expect and believe that each utility will act reasonably and responsibly to assist the State weather this crisis. We will review the balance in each memorandum account for reasonableness before authorizing recovery but, absent incompetence, malfeasance, or other unreasonableness, we would expect to authorize full recovery of all dollars spent by utilities for these programs to get California through this crisis.

The balance in each memorandum account will be included in some funding source as soon as possible. In the interim, we direct utilities to implement programs authorized herein without delay. The Governor has declared a State of Emergency. The current conditions have been seriously jeopardizing the health, safety and welfare of every Californian for months, and may continue to do so for the foreseeable future. We require each respondent utility to implement today's orders without delay as part of their public utility obligation.

### 8.2 Program Limits

We cap program authorization to the following megawatt and dollar limits:

**TABLE 3**
**INTERRUPTIBLE PROGRAM AND CURTAILMENT PRIORTY LIMITS THROUGH DECEMBER 31, 2002**

| UTILITY | INTERRUPTIBLE PROGRAM LIMIT (MW) | TOTAL ANNUAL PROGRAM DOLLAR LIMIT ($ MILLION) |
|---|---|---|
| PG&E | 2,000 | $200 |
| SCE | 2,750 | $275 |
| SDG&E | 250 | $25 |
| TOTAL | 5,000 | $500 |

We adopt these limits to prevent over-subscription or overspending if programs are not as necessary as they now appear to be. The megawatt limits apply to the total megawatts that may be subscribed to interruptible programs through December 31, 2002 without further Commission authorization. This includes the currently subscribed 2290 MW. (See Table 2.) If a currently subscribed megawatt transfers from an existing program to a new program (e.g., by exercising an opt-out option), however, that megawatt shall not be counted twice against the program total.

Similarly, the dollar limits apply to the total dollars to be spent by each respondent utility on an annual basis for total interruptible program costs, and new costs implementing changes to curtailment priorities, without further authorization. These limits shall apply separately for January 1, 2001 through December 31, 2001, and January 1, 2002 through December 31, 2002. These dollars include amounts funded in current rates, and those recorded in the memorandum account of each respondent utility.

We determine the megawatt limits by a combination of the success each utility has had to date with megawatts subscribed to interruptible programs, and the customer base of each utility. PG&E and SCE have approximately the same customer base, reflecting in some way the possible pool of potential interruptible megawatts and megawatt-hours, while SDG&E has a much smaller base. SCE has had the most program success (see Table 2). Even with a lower percentage of performance, SCE has a larger number of performing megawatts. On balance, we adopt the megawatt limits in Table 3 to reflect those variations.

Current program costs are about $100 per kW per year.[34] We apply this amount to the adopted megawatts to determine total funding authorization. The funding limits apply to all programs, including the VDRP (i.e., a pay-for-performance program, not a payment for capacity program).

These limits are reasonable under current conditions, but we must be flexible if conditions deteriorate and warrant further change. Our adopted regulatory system to permit change, however, must protect ratepayers while allowing reasonably quick response during this time of crisis.

Therefore, we authorize each respondent utility to file and serve an application, as needed, requesting a specific increase in megawatt or dollar limit. The application shall clearly state if respondent utility applies for an increase in the megawatt or dollar limit on an expedited basis, and cite any necessary authority for the Commission to act on an emergency basis.

We must have timely and accurate information about the success of the programs we order today, and the costs that are being incurred. To accomplish this objective, respondent utilities shall each file a monthly report with the Commission. The report shall be due 7 days after the end of each month, and report on all matters through the end of the immediately previous month.

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[34] Approximately $220 million is spent per year for 2,200 megawatts.

The first report shall be filed in this docket on June 7, 2001, and shall report on matters through May 31, 2001. The report shall be served on the Presiding Officer (two copies), Energy Division (three copies), the Administrative Law Judge, and any party requesting a copy.

The report shall state megawatts subscribed, program operations, program costs, program revenues, customer-incurred penalties, and any other relevant information the Commission should know to be reasonably informed. Program costs and revenues shall include all incurred costs and revenues, even if not yet spent or received (e.g., capacity programs obligate payments throughout the year even if not paid by the time of a particular monthly report). Further, the report shall include the number of interval meters that have been provided, or are committed, to program participants without charge (e.g., for BIP, VDRP).

We may propose reducing the megawatt and dollar limits going forward if these reports, along with other information (e.g., forecast reserve margins) show that continuation of these relatively expensive programs is unnecessary. That is, we seek to prevent over-subscription or over-spending if conditions change, and these programs prove unnecessary. We welcome any party filing and serving a timely pleading (e.g., petition for modification) for Commission action if, in the party's judgment, program limit reductions become appropriate.

We authorize these megawatt and dollar amounts through December 31, 2002. This will permit sufficient flexibility and authority to allow reasonable program implementation through the near term crisis. It will also, however, permit timely reassessment before continuation of these relatively expensive programs based on the then-current need.

## 9. Implementation

We are persuaded by parties that we must implement today's decision without delay. Quick implementation is needed to allow reasonable opportunity for programs to be finalized and marketed, customers to be subscribed, and meters and other equipment to be installed (to the extent feasible and necessary).

To facilitate implementation, Assigned Commissioner Wood issued a ruling on March 1, 2001 directing respondent utilities to begin crafting advice letters and tariffs. Consistent with that ruling, respondent utilities filed and served draft advice letters and tariffs on March 21, 2001 implementing the decisions in Commissioner Wood's DD. Comments and reply comments on the draft advice letters and tariffs were included in comments and reply comments on the DD. This has greatly facilitated our ability to move quickly.

As a result, we direct that within 5 days of today respondent utilities file and serve advice letters and tariffs to implement today's orders. Those advice letters and tariffs will become effective in 5 days, unless suspended by the Energy Division Director. The Director may require that respondent utilities file and serve amended advice letters and tariffs at his direction to implement today's order. Further, the Director may require each respondent utility to file and serve individual advice letters and tariffs as needed to separately implement portions of today's order.

**Findings of Fact**

1. Interruptible programs are not inexpensive, and in some cases cost the same or more than prices charged in the dysfunctional electricity wholesale market, with current interruptible programs costing about $220 million per year for about 2,200 megawatts of available interruptible load.

2. D.00-10-066 suspended until March 31, 2001 the portion of SCE's interruptible tariffs that allowed customers to either opt-out of the program, or

change their firm service levels, during a 30-day window beginning November 1, 2000, with the suspension continued by D.01-03-070.

3. D.01-01-056 suspended further assessment of penalties that customers on interruptible schedules would otherwise incur for failing to curtail upon request, along with the tolling of hours and number of curtailments.

4. During January 2001, there was almost continuous use of interruptible programs, substantially exhausting the programs for the rest of 2001.

5. Electricity market experience during January 2001 was far from the normal expectation.

6. The electricity system is operating outside reasonable bounds, or any realistic assumptions, that customers could have been expected to use in their analyses of whether or not to participate in interruptible programs.

7. On January 17, 2001, Governor Gray Davis proclaimed a State of Emergency.

8. Market conditions have dramatically changed from those that existed in prior years.

9. Businesses and other customers grow, modify processes, and make other changes over time.

10. Many SCE customers would have elected to opt out or change firm service level in November 2000 if it had not been temporarily suspended by D.00-10-066.

11. Lifting the suspension now will permit respondent utilities and the ISO to have a more reliable base of interruptible load for Summer 2001, and more knowledge of the truly available interruptible resources from which to manage conditions in Summer 2001.

12. The market became particularly chaotic in November 2000, when the number of Stage 2 and Stage 3 events began to increase.

13. SCE's current practice is to make an opt-out or change in firm service level effective with the beginning of the next billing cycle.

14. The need for existing programs is unlikely to end by March 31, 2002.

15. Limiting existing program use to one 6-hour event per day, 4 events per calendar week, and 40 hours total per month, will extend program availability.

16. The emergency circumstances exception in SDG&E tariffs requires SDG&E to interrupt customers during a system emergency even when the customers have reached their maximum hourly limit under other tariff provisions.

17. In January 2001, customers on SDG&E Schedules A-V1 and A-V2 were notified of the need to interrupt almost every day, and, as a result, many customers terminated service on these schedules.

18. All curtailments in 2001 have been called in accordance with the system emergency clause in SDG&E's tariffs, not the interruptions subject to an 80-hour per year limit in SDG&E's tariffs.

19. Modified retention of the emergency circumstances exception in SDG&E's tariffs will prevent customers' exposure to unlimited interruptions, and substantial exodus from SDG&E's interruptible tariffs.

20. PG&E's interruptible program is limited to 100 hours of interruptions, and SCE's program is limited to 150 hours.

21. Current interruptible tariffs do not limit a customer's right to continue using electricity during curtailment periods, subject to substantial penalty for failing to curtail.

22. Caliber One does not claim to be a public utility regulated by the Commission, no party claims that Caliber One is a public utility regulated by the Commission, and no evidence is presented that Caliber One is a public utility regulated by the Commission.

23. Caliber One and parties had several opportunities to raise and address Caliber One's issue concerning whether or not interruptible customers have the right to willfully refuse to comply with an interruption notice without breaching their obligations.

24. An interruptible customer's willful refusal to curtail may defeat the public purpose goal of the interruptible program in the specific instance where the customer shifts the risk of penalties from itself to others by use of insurance.

25. Interruptible programs have been largely exhausted for 2001 based on extensive use in January 2001.

26. A replacement fixed payment for capacity interruptible program is necessary.

27. A reasonably simple approach is needed for the VDRP to be successful.

28. Most customers state that their business is conducting their business, not buying and selling electricity, and not constantly monitoring the electricity market to make decisions about buying electricity or curtailing their operations.

29. A fixed rate for the VDRP, subject to limited modification as needed, is efficient and simple.

30. The Energy Division's recommendation of $0.15/kWh is too low given prices in the current dysfunctional market, but the Joint Parties recommendation of $0.50/kWh to $0.75/kWh is too high, reflecting prices at the unreasonable levels in today's dysfunctional wholesale market.

31. A dual rate for the VDRP (between day ahead and day of) is needlessly complex, and will encourage customers to withhold supply, waiting for the higher rate.

32. A minimum payment to VDRP participants provides compensation for at least some of their cost and inconvenience for participation.

33. Satisfaction and participation in an air conditioner cycling program will decline if the program is overused by the utility.

34. The CEC estimates that 14,000 MW of air conditioning load (28% of total load) occurs during the state's summertime peak demand of 50,000 MW, with about 7,000 MW commercial, and about 7,000 MW residential.

35. Comverge Technologies, Inc. can assume full responsibility for turnkey projects, take the financial risk on a pay-for-performance basis, and use existing paging companies for radio communication.

36. Comverge can use radio signals in an interruptible program with a wide range of appliances (from air conditioners to electric water heaters, pool pumps, or other electric motors) in residential, commercial or industrial settings.

37. The 20% maximum load reduction required in the current OBMC program is too onerous, and will reduce the ability of customers to use this program.

38. The economic damage criterion for participation in the OBMC program limits the candidate pool for participation.

39. Failure to account for recent conservation efforts reduces the incentive to participate in an OBMC program, while failure to recognize reasonable growth in demand over time similarly penalizes participation.

40. Measuring 5% OBMC increments against usage over the last 10 days is the most up-to-date measurement reflecting current conditions when actual system conditions otherwise require mandatory curtailments.

41. Measuring 20% OBMC total reduction against the prior year's average peak usage for the same month recognizes yearly variations, and does not penalize customers for near term demand reduction efforts.

42. Using a baseline for OBMC of the average demand for the same period will prevent comparison of off-peak with on-peak hours, or other dissimilar comparisons.

43. It will facilitate further study of SDG&E's HVAC program to provide meters and communication equipment without charge to customers who participate in the VDRP.

44. There is no net benefit to California for ISO and respondent utility programs which are similar to compete for subscribers at different prices.

45. Many customers are exempt from rotating outages because they share a circuit with an essential customer.

46. Inclusion of non-essential customers who are now on exempt circuits in the rotating outage pool increases the amount of load available for emergency curtailment by thousands of megawatts, thereby significantly reducing the frequency and duration of outages all other customers may face, and more equitably distributing the burden of outages.

47. Inclusion of non-essential customers in the rotating outage pool ensures that all non-essential customers experience the same incentive to voluntarily curtail use before mandatory curtailments are initiated, thereby assisting the entire State weather the current crisis.

48. Isolating essential from non-essential customers must be carefully studied to promote equity between customers, and to cost-effectively increase the available pool for mandatory curtailment.

49. Equity between customers is compromised by treating customers differently for purposes of rotating outages based solely on service voltage.

50. Limiting the pool of customers subject to rotating outages increases the likelihood of outages for those in the rotating outage pool, while the excluded customer is protected.

51. About 75% of transmission level customers cannot be easily curtailed by the utility without extensive interaction with, and cooperation from, the customer.

52. Limiting an essential customer's participation in interruptible programs to no more than 50% of average peak load will balance some contribution by the customer when it is feasible for the customer to do so with the customer's essential status.

53. Outages affecting fossil fuel producers, pipelines, and users, if not coordinated, may cause unacceptable jeopardy to public health and safety.

54. The ISO may give very short notice (e.g., 10 minutes) of a Stage 3 mandatory curtailment.

55. Cost-effective utility treatment of remotely and manually controlled circuits can likely be improved to promote efficiency and equity.

56. It is important to study and implement all reasonable steps for SCADA and non-SCADA execution of rotating outages to ensure that forced outages are accomplished with optimal equity and efficiency, as well as within reasonable cost.

57. The consequences of customer reclassification from essential to non-essential categories can be great given the increased occurrence of rotating outages in 2000 and 2001, and increased likelihood of rotating outages through the rest of 2001 and possibly beyond.

58. PG&E provides electric service to approximately 48,000 medical baseline customers, of whom about 22,000 are classified as "life support" customers, while SCE has about 27, 000 medical baseline customers, of whom about 2,200 are critical care customers.

59. An infrastructure currently exists in the medical community and industry to supply and inspect backup devices for vital medical equipment that need not be duplicated by utilities.

60. The number of calls to life support, critical care and medical baseline customers may be a problem if such calls are required during all Stage 3 events but not all Stage 3 events result in a rotating outage.

61. Electric service to industrial customers may be especially critical to public health and safety if, or example, the curtailment of electricity causes the release of chemicals or toxins.

62. Rotating electrical outages cause particular concern for public health and safety when they involve underground transit systems, such as BART and MUNI.

63. It is technically feasible to exempt BART from rotating outages without significant negative effects on PG&E's overall emergency response plan, and PG&E asks that the underground component of MUNI be similarly exempt.

64. PG&E includes a rotating outage block number on customer bills, but neither SCE nor SDG&E notify their customers of the rotating outage block to which the customer is assigned.

65. Customers need and expect reasonable, timely and accurate information on rotating outages, and public health and safety may depend upon it.

66. Sixteen of 28 rural counties do not have a hospital with more than 100 beds.

67. Severity of sickness or injury is not a function of the geographic location of the patient.

68. The backup or standby generation required by Office of Statewide Health Planning and Development regulation does not satisfy Commission requirements for minimal essential uses for hospitals.

69. Exempting hospitals with 100 beds or more from rotating outages does not disturb or compromise the Commission's determination to maintain at least 40% of available load for rotating outages.

70. Water and sewage treatment utilities have backup generation or other capacity for operation and storage during power interruption, and have reasonably prepared for power interruptions which may occur from a number of causes.

71. Existing rules allow water and sewer utilities to request partial or complete rotating outage exemption, or partial or complete service restoration, based on an emergency.

72. Additional funds not now available from existing rates may be needed for utility implementation of some, but not all, programs and studies ordered herein.

73. ISO rates are set by FERC.

74. PG&E and SCE have approximately the same customer base, SDG&E has a much smaller customer base, and SCE generally had the most interruptible program success.

75. Current interruptible program costs are about $100 per kW per year.

**Conclusions of Law**

1. SCE's interruptible customers should be permitted to opt out or change firm service level without complicated conditions, with an effective date of either November 1, 2000, the date beginning with the customer's next billing cycle, or a date between the date of notice and the beginning of the next billing cycle if such date is agreed to between the customer and SCE.

2. The limited time and resources of parties and the Commission are most reasonably devoted to positive solutions for Summer 2001 rather than designing more precise formulas, additional rules, deadline extensions, and other remedies to restructure prior obligations to meet current market and business realities.

3. SCE interruptible customers should have an opportunity to elect opt-out or change firm service level during a 15-day window beginning upon service of notice to customers of this option.

4. SCE should provide written notice to each affected customer within 10 days of the date the tariff becomes effective, including a calculation of the effect of selecting the November 1, 2000 date.

5. A customer who elects to opt-out or readjust firm service level back to November 1, 2000 should repay the discounts received from November 1, 2000 through the present, but not pay any otherwise incurred penalties for failure to curtail when asked during that time, and should not be assessed interest.

6. A customer who elects to opt-out or readjust now, or up to the beginning of the next billing cycle, should retain the rate discount for interruptible service through the date of any change in schedule or firm service level, but should to pay any penalties incurred for failure to interrupt when asked by the utility under the interruptible schedule through the time the opt-out or adjustment in firm service level is effective, with waiver of any penalty between the date penalties are reinstated and the date of opt-out or adjustment in firm service level.

7. SCE interruptible customers who opt out in the authorized 15-day window should not be allowed to participate for one year in either any other program that pays a capacity payment, or a similar ISO program, including the Ancillary Load Services Program.

8. Existing interruptible programs should be extended through December 31, 2002, and program use should be limited to one 6-hour event per day, 4 events per calendar week, and 40 hours total per month.

9. The emergency circumstances exception should be retained in SDG&E's interruptible program tariffs subject to a total annual limit, and the annual interruption limit should be increased from 80 to 120 hours.

10. An interruptible customer's willful refusal to comply with interruption notices does not constitute a breach of SCE's current interruptible Schedule I-6.

11. PU Code Sections 701, 728 and 743(f) give the Commission authority to regulate public utilities, and contracts between public utilities and utility customers.

12. Caliber One is not a public utility regulated by the Commission.

13. The Commission regulates the terms and conditions of interruptible tariffs and contracts between public utilities and customers, but not contracts between non-public utilities, whether or not the agreement references a regulated rate or tariff.

14. Adequate notice and opportunity to comment have been given on the insurance issue raised by Caliber One.

15. An existing or new customer should not be eligible for continued or new subscription to interruptible tariffs unless the customer files a declaration under penalty of perjury with the utility stating that the customer does not have, and will not obtain, any insurance covering payment of paying non-compliance penalties for willful failure to comply with requests for curtailment.

16. The suspension of penalty provisions imposed by D.01-01-056 should now be removed, but reinstated penalties should not apply for any customer who opts-out or changes firm service level (to the extent the change negates penalties) effective November 1, 2000 and repays discounts.

17. The new BIP program should be adopted.

18. The VDRP program should be adopted, with the rate set at $0.35/kWh.

19. SCE's existing air conditioner program should be reopened, and the new program adopted, for all customers at the several cycling options described in this decision.

20. SCE should be required to raise the issues of air quality, compatibility with other building code requirements, and customer satisfaction when marketing the 100% air conditioning cycling option.

21. The maximum OBMC curtailment percentage on a circuit should be reduced from 20% to 15%.

22. Respondent utilities should notify large customers of the OBMC within 21 days of today, and coordinate communications between interested customers.

23. The economic damage criterion should be removed from the OBMC program.

24. Meters should be provided without charge to participants in the SDG&E HVAC program if they also participate in the VDRP.

25. A customer subscribed to a utility interruptible program should not be permitted to subscribe to a similar ISO program until the customer has exhausted participation in the utility program, or be permitted to opt-out of a utility program to participate in an ISO program, but should be allowed to participate in ISO programs that are different than the utility program in which the customer is subscribed.

26. A customer subscribed to a utility interruptible program or who has been permitted to opt-out of a utility interruptible program should not be permitted to participate in the ISO's Ancillary Services Load Program nor the ISO's DRP.

27. Respondent utilities should not act as aggregators for ISO programs.

28. Respondent utilities are authorized to act as aggregators for bids in the ISO's DRP accepted as of the effective date of this order.

29. Respondent utilities should study and report on reconfiguring circuits to isolate essential from non-essential customers, and increase the pool of non-essential customers available for rotating outages by Summer 2001, Summer 2002, and beyond.

30. The Energy Division Director should have delegated authority to authorize cost-effective, reasonable circuit reconfigurations for projects up to a

cumulative total of $5 million each for PG&E and SCE, and $1 million for SDG&E.

31. Respondent utilities should include transmission level customers in rotating outages, subject to their exclusion if they are essential use customers, participate in OBMC, supply power to the grid in excess of load, jeopardize system integrity by their inclusion in rotating outages, or are otherwise exempt by the Commission.

32. Utilities should give transmission level customers a reasonable opportunity to become net suppliers to the grid at the time of a rotating outage, but failure to become a net supplier in a reasonable amount of time should result in the customer loosing the exemption.

33. A respondent utility should install automatic switching equipment, controlled by the utility, at the transmission customer's expense, if the customer refuses to drop load upon request, subject to a $6/kWh penalty for load that was not dropped.

34. Essential customers may subscribe to interruptible tariffs, but eligibility should be screened by the utility, wherein the utility should require a declaration submitted under penalty of perjury as described in this decision for the purpose of such screening, and the customer should not be permitted to subscribe more than 50% of its average peak load to interruptible service.

35. Respondent utilities should coordinate interruptions, to the extent feasible, between fossil fuel producers, pipelines and users to minimize disruption to public health and safety.

36. Respondent utilities should study and report on the cost of dispatching personnel versus installing automated equipment in remote locations to implement forced outages.

37. Utilities should implement the directions in the March 27, 2001 ACR regarding notification to customers who have been reclassified between essential and non-essential categories.

38. Reclassification complaints filed with the Commission should be processed using the Commission's expedited complaint procedure, and the burden of proof should shift to respondent utility upon the filing of a complaint that reasonably alleges the utility has acted or failed to act as required.

39. Respondent utilities should examine potential improvements to programs which notify a life support, critical care or medical baseline customer when a rotating outage likely to affect the customer is imminent, and should report to the Commission on these programs.

40. Respondent utilities should report on their recent efforts undertaken with OSHA and/or OES to address particular and unique risks to employee and public health and safety from imminent electrical outages to industrial customers in Summer 2001.

41. BART, and the underground portions of MUNI, should be exempt from rotating outages.

42. PG&E should report on the necessary and reasonable mitigation measures to which PG&E and MUNI have agreed, and the measures that PG&E has, or will, implement.

43. The Executive Director should serve a copy of this decision on other rail transit systems under Commission jurisdiction, inviting those transit systems to consider public health and safety issues affecting their systems due to the serious potential of a number of electrical outages in 2001 and 2002.

44. SCE and SDG&E should address in Phase 2 the need, desirability and reasonableness of including a rotating outage block number on each customer

bill, with a notice that the block may change without notice based on operational conditions.

45. Sick or injured people in rural hospitals can be just as sick or injured as their urban counterparts, and deserve the same level of protection for electricity services.

46. Respondent utilities should exempt hospitals from rotating outage regardless of the status of backup or standby generation, as provided in the March 23, 2001 ACR.

47. The essential customer list should be amended to include all hospitals, and respondent utilities should submit information in Phase 2 on the effect this change has had on mandatory curtailments, including the number of circuits and megawatts that are available for rotating outage before and after the change.

48. Each respondent utility should file an updated rotating outage action plan within 45 days.

49. The following should not be authorized at this time: the customer recognition program; modification of the essential customer list for water districts, sewer districts, ancillary government services, or networks; any changes in the notice provided to interruptible customers by respondent utilities; and the SLRP.

50. FERC approval is uncertain regarding ISO funding of utility interruptible programs and the costs for changed curtailment priorities.

51. A surcharge on respondent utility rates to fund new interruptible programs plus the costs for changed curtailment priorities is inconsistent with the current rate freeze, and SDG&E’s PBR, and should not be adopted.

52. The funding in DWR rates of respondent utility interruptible programs plus the costs of changed curtailment priorities is currently not an option.

53. Each respondent utility should establish a memorandum account to track all dollars it spends and receives above funds authorized in current rates to implement any decision in today's order regarding interruptible programs and curtailment priorities.

54. Each respondent utility should implement today's orders without delay as part of its public utility obligation.

55. Interruptible programs and curtailment priorities should be capped at the following megawatt and annual dollar limits:

**INTERRUPTIBLE PROGRAM
AND CURTAILMENT PRIORTY LIMITS
THROUGH DECEMBER 31, 2002**

| UTILITY | INTERRUPTIBLE PROGRAM LIMIT (MW) | TOTAL ANNUAL PROGRAM DOLLAR LIMIT ($ MILLION) |
|---|---|---|
| PG&E | 2,000 | $200 |
| SCE | 2,750 | $275 |
| SDG&E | 250 | $25 |
| TOTAL | 5,000 | $500 |

56. The megawatt limits should include currently subscribed megawatts, and should be the total megawatts that may be subscribed to interruptible programs through December 31, 2002.

57. The annual dollar limits should include amounts funded in current rates, plus those recorded in the memorandum account of each respondent utility, for total interruptible program costs, and new costs implementing changes to curtailment priorities.

58. Each respondent utility should report monthly on the programs we order today, and the costs and revenues that are being incurred.

59. Each respondent utility should file one or more advice letters with tariffs within 5 days of today to implement today's orders, with those advice letters and tariffs becoming effective in 5 days, unless suspended by the Energy Division Director.

60. This order should be effective today to allow reasonable opportunity for programs to be finalized and marketed, customers to be subscribed, and meters and other equipment to be installed for Summer 2001 program implementation.

## INTERIM ORDER

**IT IS ORDERED** that:

1. Within five days of the date of this order, respondent utilities Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall each file and serve an advice letter with revised tariffs. The advice letters with revised tariffs shall implement the directions in this order and Attachment A. Each advice letter with tariffs shall be in compliance with General Order 96-A. The advice letters and tariffs shall become effective five days after filing, unless suspended by the Energy Division Director. The Energy Division Director may require a respondent utility to amend its advice letter and tariffs to comply with the orders herein, and may require a respondent utility to file and serve individual advice letters and tariffs as needed to separately implement portions of today's order.

2. A protest to an advice letter filed and served by a respondent utility to modify the Voluntary Demand Response Program rate shall be filed and served within 10 days of the date the advice letter is filed.

3. The priority system for rotating outages stated in this order and in Attachment C shall supercede the existing priority system 10 days from today,

and shall be implemented by each respondent utility. PG&E shall exempt the Bay Area Rapid Transit District, and the underground portions of the San Francisco Municipal Railway (MUNI), from rotating outages. Within 21 days of today, each respondent utility shall notify customers using 500 kilowatts or more (average peak demand) of the adopted Optional Binding Mandatory Curtailment Program, and shall coordinate communication between customers on a circuit when one customer expresses its intent to participate. All hospitals shall be exempt from rotating outages regardless of the status of backup or standby generation.

4. Respondent utilities shall file and serve the adopted studies and reports shown in Attachment D according to the schedule, terms and conditions stated in this order and in Attachment D. Parties may file and serve comments, responses or protests as provided in Attachment D. Responses or protests to any application or advice letter filed by a respondent utility to implement any matter raised by such study or report shall be filed and served within 10 days of the date the application or advice letter is filed and served. The Assigned Commissioner and Presiding Officer, or the Administrative Law Judge, may change these dates by ruling.

5. The Energy Division Director may authorize respondent utilities to implement cost-effective, reasonable circuit reconfiguration projects to isolate essential from non-essential customers up to a cumulative total of $5 million for PG&E, $5 million for SCE, and $1 million for SDG&E.

6. Respondent utilities shall implement the notification procedures stated in the March 27, 2001 Assigned Commissioner Ruling for customers reclassified between essential and non-essential categories. Customer complaints filed with the Commission shall be processed using the Commission's expedited complaint procedure. The burden of proof shall be upon the serving utility once a

complaint is filed with the Commission that reasonably alleges the utility has acted or failed to act as required.

7. In the event MUNI files a formal complaint regarding mitigation measures to protect MUNI passengers and staff from a rotating outage, MUNI shall serve a copy on PG&E the same day that it is filed with the Commission. PG&E shall file and serve its answer within 10 days of the date the complaint is filed. The Assigned Commissioner and Presiding Officer, or the Administrative Law Judge, may change these dates by ruling.

8. The serving respondent utility shall install, at the transmission customer's expense, automatic equipment controlled by the utility to implement rotating outages if a transmission level customer is not exempt from rotating outages but fails to cooperate and drop load at the request of its serving utility. A transmission level customer who refuses to drop load before installation of equipment to implement rotating outages shall be subject to a penalty of $6/kWh for all load requested to be curtailed that is not curtailed. Transmission level customers excluded from rotating outage on the basis of being a net supplier to the grid shall have a reasonable opportunity to become a net supplier at the time of the rotating outage. Failure to become a net supplier within a reasonable amount of time shall result in the customer loosing the exemption. The $6/kWh penalty shall not apply if the customer's generation suffers a verifiable, and verified, forced outage, and during times of scheduled maintenance. The scheduled maintenance must be approved by both the Independent System Operator and respondent utility, but approval may not be unreasonably withheld.

9. Respondent utilities shall reasonably coordinate interruptions, to the extent feasible, between fossil fuel producers, pipelines and users to minimize any disruption to public health and safety.

10. Each respondent utility shall file and serve an application or advice letter seeking Commission authorization to implement an Occupational Health and Safety Administration (OSHA) or Office of Emergency Services (OES) recommendation regarding the exemption of an industrial customer from rotating outages to protect public health and safety. Respondent utility shall file this application or advice letter only if specific Commission authorization is needed but not yet available. The application or advice letter shall include a statement from OSHA and/or OES in support of the request, showing that no other reasonable means to protect public health and safety are available other than exemption from rotating outage.

11. The Executive Director shall serve a copy of this decision on Los Angeles County Metropolitan Transit Authority, Sacramento Regional Transit District, Santa Clara Valley Transportation Authority, and San Diego Trolley Incorporated. The cover letter shall invite these rail transit systems to evaluate public health and safety concerns on their systems due to the serious potential of a number of electrical outages in 2001 and 2002. It shall recommend that each system discuss the matter with their serving utility, and cooperatively implement any reasonable and necessary mitigation measures. It shall also invite each system to make a joint proposal, in cooperation with its serving utility, other rail transit systems, and the Commission's Rail Safety and Carrier Division, regarding any mitigation measures that should be considered by the Commission, and which require Commission authorization

12. SCE and SDG&E shall, and other parties may, address in Phase 2 the need, desirability and reasonableness of SCE and SDG&E including a rotating outage block number on each customer bill, with a notice that the block may change without notice based on operational conditions. Parties shall include this

issue in any Phase 2 pleadings regarding a list of issues for consideration, along with their recommendations on how and when this issue should be considered.

13. Each respondent utility shall submit information in Phase 2 on the effect of adding hospitals of less than 100 beds to the list of essential customers excluded from mandatory curtailments. The information shall include the effect on the number of circuits and megawatts that are available for rotating outage by excluding all hospitals from rotating outage compared to excluding only hospitals with 100 beds or more. The study regarding the reconfiguration of circuits to narrow exempted load shall include an assessment of isolating hospitals of less than 100 beds.

14. Each respondent utility shall report no later than in Phase 2 on the effect of including skilled nursing facilities to the list of essential customers excluded from rotating outages. The report shall state the number of affected circuits, estimated megawatts removed from rotating outage, an estimate of the effect on mandatory curtailments, and an estimate of the effect on retaining 40% of total system load available for rotating outage. The report shall also assess the reasonableness of reconfiguring circuits to narrow exempted load by isolating skilled nursing facilities.

15. Each respondent utility shall update and file its annual rotating outage action plan to include the orders herein within 45 days of the date this order is served.

16. Each respondent utility shall establish a memorandum account consistent with the orders herein. The memorandum account shall track all dollars spent above funds authorized in current rates to implement any program, activity, study, or report ordered herein. The accounting shall separately identify the cost and revenue associated with each program, activity, study or report (e.g., separately track costs and revenues for the new Base Interruptible Program,

Voluntary Demand Response Program, each curtailment study, each report). Each respondent utility may include interest on the balance. The burden to demonstrate reasonableness for future cost recovery shall be on each respondent utility. Each respondent utility shall implement the orders herein without delay consistent with its public utility obligations and responsibilities.

17. The following limits shall apply to program implementation by respondent utilities:

**INTERRUPTIBLE PROGRAM AND CURTAILMENT PRIORTY LIMITS THROUGH DECEMBER 31, 2002**

| UTILITY | INTERRUPTIBLE PROGRAM LIMIT (MW) | TOTAL ANNUAL PROGRAM DOLLAR LIMIT ($ MILLION) |
|---|---|---|
| PG&E | 2,000 | $200 |
| SCE | 2,750 | $275 |
| SDG&E | 250 | $25 |
| TOTAL | 5,000 | $500 |

The megawatt limits apply to the total megawatts that may be subscribed to interruptible programs at any one time through December 31, 2002 without further Commission authorization, including currently subscribed amounts. If a currently subscribed megawatt transfers from an existing program to a new program (e.g., by exercising an opt-out option), that megawatt shall not be counted twice against the program total. The dollar limits apply to the total dollars to be spent by each respondent utility on an annual basis for total interruptible program costs, and new costs implementing changes to curtailment priorities, without further authorization. These limits shall apply separately for January 1, 2001 through December 31, 2001, and January 1, 2002 through December 31, 2002. These dollars include amounts funded in current rates, and those recorded in the memorandum account of each respondent utility.

18. Applicant shall cite applicable authority for Commission action on an emergency basis in any application filed and served by a respondent utility for expedited Commission authorization to increase the megawatt or dollar program limit adopted herein.

19. This proceeding shall remain open for consideration of interruptible programs and curtailment priorities for Summer 2002, and any other issue or issues identified by the Commission, Assigned Commissioner and Presiding Officer, or Administrative Law Judge.

This order is effective today.

Dated April 3, 2001, at San Francisco, California.

LORETTA M. LYNCH<br>
President<br>
HENRY M. DUQUE<br>
CARL W. WOOD<br>
GEOFFREY F. BROWN<br>
Commissioners

Commissioner Richard Bilas, being necessarily absent, did not participate

I will file a concurrence

/s/ HENRY M. DUQUE<br>
Commissioner

## ATTACHMENT A

## CHANGES TO CURRENT INTERRUPTIBLE PROGRAMS, NEW INTERRUPTIBLE PROGRAMS, AND ROTATING OUTAGE PROGRAMS

## R.00-10-002

## 1. CHANGES TO CURRENT INTERRUPTIBLE PROGRAMS

**1.1 Modified Opt-Out**: Southern California Edison Company (SCE) shall notify all affected customers of the opt out options provided by this decision. Customers may opt out of SCE's interruptible program, or change their firm service level, subject to the following.

1.1.1 Customers may elect to opt-out of interruptible tariffs, or change their firm service level, during a one-time 15-day period, as provided below.

1.1.1.1 Customers may choose to opt out, or increase their firm service level as of November 1, 2000. Customers choosing this option shall pay back to SCE the total discounts, or the amount related to the change in firm service level, received since November 1, 2000. SCE will establish a payment schedule, but all payments must be received by December 31, 2001.

Since, under this option, participation in the program shall cease as of November 1, 2000, all penalties assessed after that date are void for customers opting out. Any penalties collected for non-compliance during the period after November 1, 2000 shall be used to offset the discounts received, or if they exceed the total discounts received since November 1, 2000 the difference shall be refunded.

For customers adjusting their firm service level as of November 1, 2000, penalties based on non-compliance with the adjusted firm service level shall be paid in full.

1.1.1.2 Customers may choose to opt out as of the first billing period following the date notice is given to SCE, or an earlier date between the date of notice and the beginning of the next billing cycle if the customer and SCE both agree to the earlier date. Customers choosing this option shall not be required to pay back any discounts received. All penalties for non-compliance shall be paid. Penalties assessed for non-compliance between reinstatement of penalties and the date of opt-out are waived.

1.1.2 Customers who opt-out during the one time 15-day period may not participate for in a load reduction program that pays per kW for the remainder of 2001 or participate in the ISO's DRP or Ancillary Services Load Program. There is no restriction on participating in other UDC interruptible programs, as long as customers are only paid once for a load reduction.

**1.2 Other Changes to Existing utility distribution company (UDC) Capacity Interruptible Programs:**

1.2.1 Limit program use to one 6-hour event per day.
1.2.2 Limit program to no more than 4 events in any one calendar week.
1.2.3 Limit program to 40 hours per month.
1.2.4 Programs extended to December 31, 2002.
1.2.5 Insurance: Insurance may not be used to pay non-compliance penalties for willful failure to comply. Eligibility for an interruptible program will require that each customer execute an declaration that it does not have, and will not obtain, such insurance.
1.2.6 The AV programs of SDG&E shall have a 120-hour annual limit on the total number of hours a participant may be called for any reason.
1.2.7 Nothing in this decision opens the existing UDC capacity interruptible programs (e.g. I-6, E-20 non-firm, AV-1) to additional customers.

**1.3 Suspension of Interruptible Programs:**
The UDCs shall, within 3 days, notify all interruptible customers that the suspension of interruptible program penalties and the tolling of hours and number of curtailment events has ended. Three days from the date of the notice, the UDCs shall resume operation of the interruptible programs as modified by this decision, including the

assessing of penalties and charging the number of hours and events toward the program maximums.

**1.4 Participation in Additional Programs:**
Participants in the existing interruptible program who have fulfilled the annual maximum obligation under the program, may participate in the Base Interruptible Program without loss of discounts earned through existing program participation.

During the month of November participants in both the existing interruptible program and the Base Interruptible Program may select which program they shall participate in during 2002. If no selection is made, the customer shall participate in the existing program and participation in BIP shall be terminated as of 1/1/02.

## 2. NEW INTERRUPTIBLE PROGRAMS

### 2.1 Modified Joint Proposal: New Base Interruptible Program (BIP)

2.1.1 Elements

2.1.1.1 Limit to one 4-hour event per day.
2.1.1.2 Limit to 10 events per month, and 120 hours per year.
2.1.1.3 Annual opt-out option in November, effective January 1.
2.1.1.4 Incentive of $7 per kW-month credit on bill.
2.1.1.5 $6 per kWh penalties for all energy consumption in excess of the customer's firm service level.
2.1.1.6 The bill credit is based on the difference between each month's average peak period demand and a customer selected firm service level.

2.1.2 Program open to customers who can commit to curtail at least 15% of load, with a minimum load drop of 100 kW per event.

2.1.3 Load can only be committed to one program, and participants paid only once for a load reduction. Customers currently enrolled in a UDC interruptible program, or the ISO's DRP, must complete all annual obligations to that program before being eligible for this program. In addition, BIP participants shall not participate in the ISO's Ancillary Services Load Program.

2.1.4 New program participants receive an interval meter and communication equipment without charge, if needed. Costs will be charged as a program expense. Participants receiving free equipment will be required to remain in the program through one full year.

## 2.2 Voluntary Demand Response Program (VDRP)

UDC operated program that pays for performance with no reservation payment and no penalties.

2.2.1 Payment is $0.35/kWh.

2.2.2 Baseline for evaluating load response will be the average of the immediate past 10 similar days. Similar days are either business days or weekend days and holidays. The baseline will be calculated on an hourly basis using the average of the same hour for the 10 days. The 10 similar days will exclude days when the customer was paid to reduce load or was subject to a rotating outage.

2.2.3 The program is open to customers who can commit to curtail at least 15% of load, with a minimum load drop of 100 kW.

2.2.4 When the ISO notifies UDCs that load relief is needed, customers are notified of need and bids are requested (bids are for offered kWhs for a specific time). Customers respond with offered kWhs and the UDC either agrees or rejects the bids. Requests may be made the day before or for the same day. UDCs can request bids multiple times for the same hours as conditions change. In their tariffs, UDCs will specify criteria for accepting bids. The primary factor should be first-come first-served, but consideration of time needed versus time bid, and past non-compliance can be included in the criteria.

2.2.5 Once a bid is accepted, if the interruption is cancelled by the UDC the customer is paid the lesser of the hours bid, the hours requested, or 2 hours.

2.2.6 New program participants receive an interval meter and communication equipment without charge if needed. Costs will be charged as a program expense. Participants receiving free equipment will be required to remain in the program through one full year and to bid for and fully comply with the bid requirements during at least 10 events. If participants fail to meet requirements they will be charged the cost of installing any meter and communication equipment provided without charge.

2.2.7 VDRP participants shall not participate in any ISO ancillary services or pay for performance program.

**2.3 Air Conditioner Cycling Programs – Commercial and Residential Agricultural and Pumping Programs**

2.3.1 SCE shall reopen its current air conditioner cycling program at all cycling options.

2.3.2 SCE shall offer a new air conditioner cycling program paying twice the existing rates for an unlimited number of events. Events are limited to 6 hours in any one day.

2.3.3 SCE shall explore load control programs for electric uses other than air conditioning (e.g. electric water heaters) and file an advice letter proposing any program it determines is reasonable.

2.3.4 Pacific Gas & Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall explore the most reasonable options for implementing an air conditioner cycling program, or other electric interruption programs, targeted to residential and small commercial customers. PG&E and SDG&E shall each file an advice letter by May 1, 2001 which analyzes the alternatives, and seeks approval of the alternatives that will produce the greatest verifiable load reduction at the least cost.

2.3.5 SCE shall reopen its current agricultural and pumping interruptible tariff, and extend the tariff through December 31, 2002.

**2.4 Optional Binding Mandatory Curtailment Program**

Elements of Optional Binding Mandatory Curtailment (OBMC) Program.

2.4.1 The OBMC program exempts participants from rotating outages if they can reduce the load on their entire circuit by the required amount for the entire duration of every rotating outage.

2.4.2 The OBMC program operates only when firm load reductions are required (i.e., concurrent with rotating outages).

2.4.3 The baseline used to determine if the required load reduction has been obtained will be the average load of the immediate past 10 similar days during the period of the interruption. Similar days are either business days or weekend days and holidays. The 10 similar days will exclude days when the OBMC program operated and paid load reductions.

2.4.4 Load reductions will be requested in increments of 5%.

2.4.5 Participants must have the ability to reduce circuit load by 15%. The baseline used to determine if the 15% reduction can be met is the prior year's, same month, average peak period usage, adjusted for major changes in facilities. However, the customer must be able to produce at least a 10% load reduction based on the criteria in 2.4.3.

2.4.6 UDCs are required to facilitate circuit aggregation when requested by customer.

2.4.7 The failure to reduce load as required will result in penalties equal to $6/kWh for all excess energy. If a participant fails to reduce circuit load to within 5% of the required amount on two occasions in any one year the customer's participation in the program shall be terminated and the customer shall be prohibited from participating in an OBMC program for 5 years.

2.4.8 Program participants shall pay the cost of any equipment required to participate in the program.

2.4.9 OBMC participants shall not participate in a capacity interruptible program such as BIP or the ISO's DRP. OBMC participants may participate in the VDRP program, but shall not be paid for any load reductions occurring during an OBMC call.

### 2.5 SDG&E's HVAC Program

No specific funding for this program, but HVAC participants who enroll in the Voluntary Demand Response Program are eligible for free meters and communication equipment, and to the incentives contained in that program.

## 3. ROTATING OUTAGE PROGRAMS: EQUITY

### 3.1 Reconfiguring Circuits

3.1.1 By June 1, 2001, PG&E, SCE and SDG&E shall each file and serve a report. The report shall list circuits capable of being reconfigured to increase the amount of load available for rotating outages and the least cost method to achieve that load reduction. The list shall include the amount of additional load added to the rotating outage pool, the time required to complete the reconfiguration, a description of the reconfiguration, and the cost of the reconfiguration. Individual reconfigurations on the list shall be limited to those that do not exceed $500,000. Reconfiguration means any change to a circuit including creating new circuits, installing switching devices, or other adjustments that result in an increase in load available to rotating outages. PG&E, SCE and SDG&E shall sort the list in three ways: by cost, by amount of additional megawatts added to the rotating outage pool, and by date the reconfiguration can be accomplished. Each report shall also identify any alternative means of achieving the goal less expensively. PG&E, SCE and SDG&E shall each make a recommendation on whether or not to implement any or all reconfigurations and or alternatives.

3.1.2 In the reconfiguration study ordered in 3.1.1, respondent utilities shall include the reconfiguration of circuits containing rural hospitals.

### 3.2 Include Most Transmission Level Customers in Rotating Outages

UDCs shall include transmission level customers in rotating outages, subject to the exclusions permitted for essential use customers and customers participating in OBMC. Transmission level customers who are supplying power to the grid in excess of their load at the time of the outage shall be excluded from rotating outages. In addition, if any transmission customers cannot be included in the rotating outage pool because of system integrity concerns, the UDC shall report to the Energy Division on those exclusions. A customer who refuses to drop load when required shall be charged a penalty of $6/KWh for all KWh taken off the grid and the utility shall install automatic switching equipment at the customer's expense.

### 3.3 Hospitals

UDCs shall include all hospitals on the list of essential customers, and exempt them from rotating outages.

### 3.4 Essential Customers

Essential customers may participate in interruptible tariffs for up to 50% of their load, but eligibility shall require a demonstration of either back-up generation or a reasonable ability to meet essential needs when interrupted. This may be accomplished by a declaration under penalty of perjury submitted to the utility.

### 3.5 SCADA and Non-SCADA

UDCs shall file and serve a report by June 1, 2001 stating the cost of dispatching personnel versus installing automated equipment in remote locations to implement rotating outages. The report shall state any changes the utility has made or is making.

## 4. ROTATING OUTAGE PROGRAMS: PROTECTIONS

### 4.1 OUTBOUND CALLING PROGRAM

UDCs are required to operate an outbound calling program to notify required customers of imminent rotating outages, giving priority to customers on life support or critical care. Once a rotating outage is called, UDCs are required to undertake their best efforts to contact customers on life support, critical care customers, customers with a load of over 300 kW, customers who have shown that they are subject to major economic damage, and customers who have shown a clear and imminent danger to personal health or safety.

In addition, UDCs shall file and serve a report by June 1, 2001 describing their outbound calling program, including any changes they have made to improve the outbound calling program and the program's operations. As part of the report, UDCs shall identify the time required to notify all required customers for an outage of 1%, 5%, 10%, 15% and 20% of peak load.

### 4.2 Offices of Emergency Services (OES)

UDCs shall file and serve a report, by June 1, 2001, describing any recent efforts undertaken to address risks to public health and safety from electrical outages to industrial customers.

### 4.3 BART and MUNI

PG&E shall exempt BART and the underground portion of MUNI from rotating outages. PG&E and MUNI shall also jointly identify any additional measures necessary to ensure the safety of MUNI passengers and staff. PG&E shall file and serve a report by May 1, 2001 on measures taken to implement safety of MUNI passengers and staff.

### 4.4 Other Rail Transit

The Executive Director shall serve a copy of this decision on other rail transit systems under our jurisdiction (i.e., Los Angeles County Metropolitan Transit Authority, Sacramento Regional Transit District, Santa Clara Valley Transportation Authority, and San Diego Trolley Incorporated). The Executive Director shall invite each transit agency to make a joint proposal with its serving utility, other rail systems, and the Rail Safety and Carrier Division regarding any rotating outage mitigation measures that should be considered by the Commission.

### 4.5 Utility Outage Notification plans:

Additional changes to notification plans (e.g., outbound calling to customers with special needs, inbound calling for information, call center response, notice to cities, information on bills including rotating outage block number on SCE and SDG&E customer bills) shall be studied further in Phase 2. The definition of special groups shall also be studied in Phase 2.

**(END OF ATTACHMENT A.)**

# ATTACHMENT B

## DECISION NO. 91584: PRIORITY SYSTEM FOR ROTATING OUTAGES

1. **Essential Customers** – Normally Exempt from Rotating Outages.

   A. Government and other agencies providing essential fire, police, and prison services.

   B. Government agencies essential to the national defense.

   C. Hospitals with 100 beds or more.

   D. Communication utilities, as they relate to public health, welfare and security, including telephones.

   E. Navigation communication, traffic control, and landing and departure facilities for commercial air and sea operations.

   F. Electric utility facilities and supporting fuel and fuel transportation services critical to continuity of electric power system operation.

   G. Radio and television broadcasting stations used for broadcasting emergency messages, instructions, and other public information related to the electric curtailment emergency.

   H. Water and sewage treatment utilities may request partial or complete rotating outage exemption from electric utilities in times of emergency identified as requiring their service, such as fire fighting.

   I. Areas served by networks, at utilities' discretion.

   J. Binding Mandatory Curtailment Plan: Any customer meeting both the criteria for Economic Damage and those following.

   The customer would be required to file with the utility an acceptable binding energy and load curtailment plan. The customer would agree to curtail electric use on his entire circuit by the amount being achieved via rotating outages. The customer's plan would show how reduction on the entire circuit could be achieved in 5 percent increments to the 20 percent level,[1] and show how compliance can be monitored and enforced. Since the required curtailment level would have been requested prior to the rotating outage stage, the customer would have to maintain the required reduction during all rotating outage periods. Several customers on a circuit could file a joint binding plan to guarantee the required curtailment from the entire circuit.

Note: Protection cannot be guaranteed because daily circuit switching may temporarily change a customer's outage block and priority classification.

**2. Economic Damage Customers**

As circumstances permit, individual warning of rotating outage plans would be given to large customers having demand of 300 kW or more, and to other customers upon their showing or need to show major economic damage or clear and imminent danger to personal health or safety, in order to qualify for this category. Individual timely warning could not be guaranteed either because of time, manpower, or communication limits, or because of daily circuit switching which could temporarily change a customer's outage block number.

**3. All Other Customers**

Customers not qualifying for higher priority. Warning and other relevant information would be informed by mass media, and no special treatment or individual notification would generally be given.

**(END OF ATTACHMENT B.)**

[1] Changed from 50 percent by D.82-09-028.

# ATTACHMENT C

## ADOPTED PRIORITY SYSTEM FOR ROTATING OUTAGES

**1. Essential Customers** – Normally Exempt from Rotating Outages

A. Government and other agencies providing essential fire, police, and prison services.

B. Government agencies essential to the national defense.

C. Hospitals.

D. Communication utilities, as they relate to public health, welfare and security, including telephones.

E. Navigation communication, traffic control, and landing and departure facilities for commercial air and sea operations.

F. Electric utility facilities and supporting fuel and fuel transportation services critical to continuity of electric power system operation.

G. Radio and television broadcasting stations used for broadcasting emergency messages, instructions, and other public information related to the electric curtailment emergency.

H. Water and sewage treatment utilities may request partial or complete rotating outage exemption from electric utilities in times of emergency identified as requiring their service, such as fire fighting.

I. Areas served by networks, at serving utility's discretion.

J. Rail rapid transit systems as necessary to protect public safety, to the extent exempted by the Commission.

K. Customers served at transmission voltages to the extent that (a) they supply power to the grid in excess of their load at the time of the rotating outage, or (b) their inclusion in rotating outages would jeopardize system integrity.

L. Optional Binding Mandatory Curtailment Program (OBMC): Any customer, or customers, meeting the following criteria.

The customer must file an acceptable binding energy and load curtailment plan with the utility. The customer must agree to curtail electric use on the entire circuit by the amount being achieved via rotating outages. The customer's plan must show how reduction on the entire circuit can be achieved in 5 percent increments to the 15 percent level, and show how compliance can be monitored and enforced. The customer must maintain the required reduction during the entire rotating outage period. The required curtailment level is requested prior to commencement of Stage 3. Several customers on a circuit may file a joint binding plan to guarantee the required curtailment from the entire circuit. Each utility shall facilitate communication between customers on a circuit if any customer expresses interest in enrolling in the OBMC program.

Note: Protection cannot be guaranteed because daily circuit switching may temporarily change a customer's outage block and priority classification.

## 2. Outage Notification

A. Life Support and Critical Care

Life support and critical care customers shall be notified by recorded or other message of a rotating outage to which they will be affected. The call is not required until a rotating outage is imminent. Utilities must undertake their best efforts to inform these customers.

B. Large Customers, Economic Damage Customers, and Danger to Health and Safety

As circumstances permit, individual warning of rotating outages will be given to large customers having demand of 300 kW or more. It will also be given to other customers upon their showing to the utility of major economic damage, or clear and imminent danger to personal health or safety. Individual timely warning can not be guaranteed, however, because of time, manpower, or communication limits, or due to daily circuit switching which may temporarily change a customer's outage block number.

C. All Other Customers

Warning and other relevant information may be provided by mass media, with no special treatment or individual notification generally given.

**(END OF ATTACHMENT C.)**

# ATTACHMENT D

## ADOPTED STUDIES AND REPORTS

**1. STUDIES AND REPORTS:** Each respondent utility shall file and serve the following studies and reports:

| ITEM NO | STUDY OR REPORT | DATE DUE |
|---|---|---|
| 1 | Reconfiguring circuits to isolate essential from non-essential customers. Study will examine essential customers, including, but not limited to, rural hospitals and networks. Study will also look at alternatives (e.g., backup generation). (Decision Section 6.1.1.) | June 1, 2001 |
| 2 | SCADA versus non-SCADA implementation of rotating outages. (Decision Section 6.1.5.) | June 1, 2001 |
| 3 | Outbound calling program. (Decision Section 6.2.1.) | June 1, 2001 |
| 4 | OSHA / OES / utility measures for industrial customers regarding employee or general public health and safety. (Decision Section 6.2.2.) | June 1, 2001 |
| 5 | MUNI. (Decision Section 6.2.3.) | May 1, 2001 |
| 6 | Existing and new methods and systems for more advance notification of rotating outages. (Decision Section 7.4.) | May 1, 2001 |
| 7 | Monthly report on interruptible and outage programs. (Decision Section 8.2.) | First report due on June 7, 2001 |

**A. Items 1-6**: Each study or report shall be filed in this proceeding, and served on the service list. Except for service on the Commission, each respondent utility may serve a Notice of Availability on the service list, even if the report is less than 75 pages, unless a party has previously informed respondent utility of its desire to receive a complete copy. (Rule 2.3 of the Commission's Rules of Practice and Procedure.) Item 5 applies to PG&E only.

**B. Item 7**: Monthly reports shall be filed in this proceeding, and served on the Presiding Officer (two copies), Energy Division (three copies), the Administrative Law Judge (one copy), and any party who requests a copy.

2. **COMMENTS, RESPONSES, PROTESTS:** Parties may file and serve comments, responses or protests to a filed study or report, and shall file and serve such pleadings within 10 days of the date the study or report is filed and served. Similarly, if respondent utility files and serves an application or advice letter to implement any matter raised by such study or report, responses or protests shall be filed and served within 10 days of the date the application or advice letter is filed and served. The Assigned Commissioner and Presiding Officer, or the Administrative Law Judge, may change these dates by ruling.

   MUNI may at any time file a formal complaint regarding mitigation measures to protect MUNI passengers and staff from a rotating outage. MUNI shall serve a copy of any such formal complaint on PG&E. PG&E's answer to any such formal complaint shall be filed and served within 10 days of the date the complaint is filed. The Assigned Commissioner and Presiding Officer, or the Administrative Law Judge, may change this date by ruling.

3. **UPDATE TO UTILITY ACTION PLANS**

   Each respondent utility shall file and serve an update to its action plan within 45 days of the date this order is served. The action plan shall be filed in this proceeding and served on the service list. Except for service on the Commission, each respondent utility may serve a Notice of Availability on the service list, even if the action plan is less than 75 pages, unless a party has previously informed respondent utility of its desire to receive a complete copy.

**(END OF ATTACHMENT D.)**

**ATTACHMENT E**

CXW / BWM / t94 3 / 27 / 2001

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Order Instituting Rulemaking into the operation of interruptible load programs offered by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and the effect of these programs on energy prices, other demand responsiveness programs, and the reliability of the electric system. | Rulemaking 00-10-002<br>(Filed October 5, 2000) |

# PRESIDING OFFICER AND ASSIGNED COMMISSIONER RULING REGARDING CUSTOMER RECLASSIFICATION BETWEEN ESSENTIAL AND NON-ESSENTIAL CATEGORIES FOR ROTATING OUTAGES

## 1. Summary

Essential and non-essential customers reclassified between June 1, 2000 and the date of notice shall be given individual written notice of the reclassification. The notice shall advise the customer that questions should first be discussed with the utility within 15 days of the date of the notice, and that unresolved disputes may be brought to the Commission by complaint. Notice shall be on the reclassified customer, not to all customers on the affected circuit.

Before implementing future reclassifications, utilities shall provide advance written notice to the customer. The reclassification shall not become effective sooner than 15 days after the date of the notice. The notice shall advise the customer that questions should first be discussed with the utility, and unresolved disputes may be brought to the Commission by complaint. Notice shall be on the reclassified customer, not to all customers on the affected circuit.

**2. Priority System for Curtailment of Electricity and Annual Action Plans**

In the 1970's, the Commission adopted a priority system for the curtailment of electricity during periods when demand exceeds supply. (Decision (D.) 86081 (July 7, 1976), 80 CPUC 157.) The adopted priority system, as modified by later orders, separately identifies essential customers from other customers. (D.91548 (April 15, 1980), 3 CPUC2d 510.)

Essential customers are normally exempt from rotating outages because they provide a service necessary for the public health, safety, or welfare. These include government agencies providing critical fire, police, prison, and national defense services; hospitals with 100 beds or more; and other specifically identified customers. (D.91548, 3 CPUC2d 510, 532-3.) Utilities file annual action plans regarding curtailment priorities that affect essential customers, including implementation of rotating outages. (D.91548, 3 CPUC2d 510, 523-525, 528 at ordering paragraph 4.)

**3. Discussion**

Utilities review customer classification as necessary, including as part of each annual action plan. Necessary customer reclassification based on updated or new information has always been important, but was of less consequence when the probability of rotating outages was small. The consequences of reclassification, however, can now be great, given the experience of rotating outages in 2000 and 2001, and the increased likelihood of rotating outages through the rest of 2001 and possibly beyond.

Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) have reclassified many customers within the last year as part of ongoing reviews, and annual action plan updates. These reclassifications have included thousands of customers who share circuits with former essential or non-essential customers. Individual customer notice was not provided. Coverage in the news media and elsewhere, however, has resulted in both customer confusion, and questions regarding whether or not the reclassifications comply with Commission orders.

Each reclassified customer deserves the right to be notified of an important change affecting service. Each reclassified customer has the right to question an important change to ensure that the change complies with law, as well as Commission rules and orders. Each reclassified customer has the right to file a complaint if the customer believes the change is in error.

Notice must be on the reclassified customer. Notice need not be on every customer on a circuit affected by the reclassification. Wider notice is not required because circuits may be reclassified at any time for any number of operational reasons. That is, an essential customer might be transferred from one circuit to another due to operational factors, with resulting effects on all other customers on the two circuits. The only customer with standing to address the reclassification, however, is the customer whose status is reclassified between essential and non-essential, not each customer whose service changes as a consequence.

This matter must be addressed immediately because rotating outages have occurred, and may continue. As a result, I direct PG&E, SCE, and SDG&E to immediately implement the notification procedures described below.

The urgency of this matter requires that PG&E, SCE and SDG&E implement this ruling without delay. I will refer the matter to the full Commission for confirmation at the earliest reasonable opportunity. (Public Utilities Code Section 310.)

**IT IS RULED** that:

1. Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall immediately notify each customer reclassified from either an essential to a non-essential category, or from a non-essential to an essential category, between June 1, 2000 and the date of the notice. The notification shall be served on each customer within 15 days of today, and shall alert the customer of the change. It shall provide an explanation of the priority system, describe how it is implemented by the utility, and include excerpts from relevant Commission decisions as necessary (e.g., Appendix B to D.91548.) It shall advise the customer that questions regarding the reclassification should first be discussed with the utility. It shall state that, absent written objection served on the utility within 15 days of the date of the notice, the reclassification shall be considered undisputed. The notice shall state that unresolved disputes may be brought to the Commission by customer-filed complaint, pursuant to Rules 9 through 13.2 of the Commission's Rules of Practice and Procedure, and such complaint must be filed with the Commission. The notice shall state that a complaint brought to the Commission must allege and show that the utility has acted or failed to act in violation of law, or in violation of any order or rule of the Commission, by the utility improperly implementing, or failing to follow, the Commission's adopted priority system. The burden shall be on the utility to defend its implementation and reclassification. The notice shall point out that the complaint will be filed and processed using the Commission's expedited complaint procedure. The notice shall only be served on the customer who is reclassified, not a customer whose service was or is changed because it shares a circuit with a reclassified customer. The utility is not required to automatically reverse the reclassification of any customer otherwise reclassified during the period from June 1, 2000

through the date of notice, but may reverse the reclassification if the customer presents sufficient evidence to convince the utility to do so. The utility shall, however, reverse the reclassification upon direction from the Commission staff or the Commission if the customer files a complaint and the complaint is resolved either informally or formally.

2. Effective immediately, PG&E, SCE and SDG&E shall provide advance written notice to a customer when the customer is scheduled to be reclassified from either an essential to a non-essential category, or from a non-essential to an essential category. The reclassification shall not become effective sooner than 15 days after the date of the notice. The notice shall contain all the information required in Ordering Paragraph 1. The notice need only be served on the customer who will be reclassified, not a customer whose service will change because it shares a circuit with a reclassified customer.

3. Within 3 days of today, PG&E, SCE and SDG&E shall each serve by mail and electronic mail on the Commission's Public Advisor a master draft of each notice described in Ordering Paragraphs 1 and 2. Service shall be performed on both Robert Ferraru and Norman Carter, with electronic mail service on rtf@cpuc.ca.gov and nhc@cpuc.ca.gov. Electronic mail service shall also be performed on the service list, with limited paper service as required by previous ruling (e.g., December 7, 2000). The Public Advisor shall provide comments on the drafts as soon as possible. Utilities shall incorporate all changes recommended by the Public Advisor.

Dated March 27, 2001, at San Francisco, California.

/s/ CARL WOOD
Carl Wood
Presiding Officer
Assigned Commissioner

**(END OF ATTACHMENT E.)**

**ATTACHMENT F**

CXW/BWM/eap 3/23/2001

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Order Instituting Rulemaking into the operation of interruptible load programs offered by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and the effect of these programs on energy prices, other demand responsiveness programs, and the reliability of the electric system. | Rulemaking 00-10-002<br>(Filed October 5, 2000) |

## PRESIDING OFFICER AND ASSIGNED COMMISSIONER RULING ON EMERGENCY MOTIONS

### 1. Summary

The emergency motions of Memorial Health Services and Catholic Healthcare West are granted in part. Southern California Edison Company and Pacific Gas & Electric Company shall immediately classify all hospitals with 100 beds or more as essential customers exempt from rotating outages regardless of the status of backup or standby generation. These hospitals shall be exempt from rotating outages within 5 days of today. If unable to exempt such hospitals from rotating outages within 5 days from today, each such utility shall, within 4 days of today, file and serve a motion requesting an extension, with a detailed statement of its plan for implementing this ruling.

### 2. Motions and Responses

On March 20, 2001, an emergency motion was filed by Memorial Health Services (MHS). MHS asserts that Southern California Edison Company (SCE) is subjecting hospitals to rotating outages. MHS requests an immediate order directing SCE to classify all hospitals as essential customers exempt from rotating outages.

On March 21, 2001, a similar emergency motion was filed by Catholic Healthcare West (CHW). CHW requests an immediate order directing SCE and Pacific Gas & Electric Company (PG&E) to classify all hospitals as essential customers exempt from rotating outages.

SCE responded on March 21, 2001. SCE asserts that it has properly implemented Commission orders and directions, and includes a hospital in rotating outages when the hospital has adequate backup generation.

### 3. Priority System for Curtailment of Electricity

In the 1970's, the Commission adopted a priority system for the curtailment of electricity during periods when demand exceeds supply. (Decision (D.) 86081 (July 7, 1976), 80 CPUC 157.) The adopted priority system, as modified by later orders, separately identifies essential customers from other customers. (D.91548 (April 15, 1980), 3 CPUC2d 510.) It defines essential customers as those normally exempt from rotating outages because they provide a service necessary for the public health, safety, or welfare. These include government agencies providing critical fire, police, prison, and national defense services. Under the Commission's rules, hospitals with 100 beds or more are essential customers, and are normally exempt from rotating outages. (D.91548, 3 CPUC2d 510, 532.)

Utilities were ordered to file action plans, which were reviewed in subsequent proceedings. In one such review, Commission staff stated that customers with sufficient standby generating equipment for their essential load should not be routinely protected from rotating outages because this double protection may jeopardize other equally essential customers. Staff recommended "that the utilities be directed to evaluate the adequacy of the standby generating equipment of protected customers and to consider removing them from the lists of essential use customers." (D.82-06-021 (June 2, 1982), Cal. PUC LEXIS 537.) The Commission adopted the staff recommendation. (D.82-06-021, Findings of Fact 2 and 3.)

## 4. Hearing

Hearing was held on the emergency motions on March 22, 2001. MHS and CHW presented three witnesses in support of the motions. Statements in support of the motions were also made by the California Association of Health Facilities (CAHF), plus the University of California and California State University (which include several medical centers). CAHF also asks that the exemption be extended to include all skilled nursing facilities.

MHS and CHW presented evidence that SCE curtailed electricity service to two hospitals on March 19, 2001. According to MHS and CHW, SCE now includes a hospital in rolling outages if the hospital has backup generation.

MHS and CHW assert that SCE does not, however, make an evaluation of the adequacy of the backup generation. Rather, it is their understanding that SCE makes this determination based on whether or not the hospital complies with Office of Statewide Health Planning and Development (OSHPD) regulations. While those regulations require backup emergency generation equipment, they only protect a hospital's critical functions, according to MHS and CHW, such as the cessation of procedures already underway, and the continued maintenance of a small and explicitly defined list of minimal hospital functions.

MHS and CHW testify that PG&E applies either the OSHPD standard, or another standard. In either case, however, the same unacceptable result is reached, according to MHS and CHW.

SCE affirms its use of OSHPD regulations, and contends these regulations represent a reasonable, objective means to evaluate whether hospital facilities possess adequate standby generation. PG&E states that it discusses the adequacy of backup generation with its customers, and generally relies on a customer's representation of adequacy.

Neither PG&E nor SCE oppose the motions, but each note that other groups may ask for similar exemption, with expansion of the number of exempted customers negatively affecting other customers. SCE asks that any ruling on the motions indicate the extent to which other essential customer classifications are impacted, and the extent to which the standby generation rule adopted in Decision No. 82-06-021 applies.

## 5. Discussion

The Commission's concern is that essential customers have adequate and sufficient emergency generation for their essential load. We define minimal essential uses for hospitals to include:

> "critical facilities such as operating room, emergency room, intensive care, life-support machines, diagnostic machines, refrigeration for medicines, communications, and minimal lighting for health and safety." (D.91548, Appendix B.)

SCE may not have unreasonably tried to apply an objective standard, and concluded that the OSHPD requirements meet Commission orders. The uncontroverted testimony here, however, shows that the minimal backup generation required by OSHPD regulations does not satisfy Commission requirements for adequate and sufficient backup generation to meet essential uses.

Similarly, PG&E may not have unreasonably tried to implement Commission orders, and concluded that its process for screening hospitals with backup generation complies with Commission directions. The evidence shows, however, that PG&E and hospital customers have not clearly communicated on the ability of each hospital's backup generation to satisfy the Commission's definition of essential uses for hospitals.

PG&E and SCE each represent that granting these motions will not compromise their ability to meet the Commission's requirement of having at least 40% of their load available for rotating outages. This factor is an important consideration, since granting the motions means other customers face a greater probability of more frequent, and potentially longer, outages as a result. The Commission has generally balanced these competing interests, however, and determined that maintenance of least 40% of available load for rotating outages is reasonable. Today's ruling does not disturb or compromise that determination.

Therefore, the MHS and CHW motions are granted in part. The motions ask for the exemption of all hospitals from rotating outages. Existing Commission orders, however, define as essential only those hospitals with 100 beds or more. The motions are granted for hospitals with 100 beds or more.

Whether or not to expand routine exemption from rotating outages to all hospitals is currently before the Commission.[1] I will not prejudge the outcome of the Commission's deliberations. Thus, I decline to extend this ruling to cover all

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[1] March 16, 2001 Draft Decision of Commissioner Wood; Item 6 on the Commission's agenda for the meeting of March 27, 2001.

hospitals. If, however, the Commission modifies the definition of essential customer to include all hospitals, PG&E and SCE shall comply with such order, including the determination herein that hospitals shall not be excluded from the essential customer category based on backup generation.

PG&E reports that it may take weeks to implement this ruling, but on further examination may be able to implement this ruling in as soon as 5 days. The urgency of this matter requires that each utility implement this order without delay.

As a result, each utility should immediately modify its rotating outage implementation plan to exclude each hospital in its service area with 100 beds or more from all rotating outages. This exclusion should be implemented no later than 5 days from today. If either utility is unable to implement this ruling within 5 days, that utility should, within 4 days from today, file and serve a motion requesting an extension, with a detailed statement of its plan for implementing this ruling.

This ruling does not go beyond the instant motions. That is, it does not disturb any Commission order regarding other essential customers, including consideration of backup generation. Moreover, it does not disturb utility implementation of those orders. Rather, this ruling applies to utility interpretation and implementation of Commission orders regarding hospitals with 100 beds or more.

The record does not show whether or not extending the exemption to skilled nursing facilities will jeopardize each utility's ability to meet the Commission's requirement of having at least 40% of load available for rotating outages. CAHF presents no evidence in support of its request regarding the effect on other customers. Extending the exclusion to skilled nursing facilities will exclude many more circuits from rotating outages, including all customers who share the excluded circuit with a skill nursing facility. As the pool of customers available for rotating outage declines, all remaining non-essential customers face an increased probability of more frequent, and longer, outages. Without evidence regarding the effect on other customers, this ruling is limited to the specific motions and evidence presented here.

**IT IS RULED** that the March 20, 2001 and March 21, 2001 emergency motions of Memorial Health Services and Catholic Healthcare West are granted in part. Southern California Edison Company and Pacific Gas & Electric Company shall immediately classify all hospitals with 100 beds or more as essential customers exempt from rotating outages regardless of the status of backup or standby generation. These hospitals shall be exempt from rotating outages within 5 days of today. If unable to exempt such hospitals from rotating outages within 5 days from today, each such utility shall, within 4 days of today, file and serve a motion requesting an extension, with a detailed statement of its plan for implementing this ruling.

Dated March 23, 2001, at San Francisco, California.

/s/ CARL WOOD
Carl Wood
Presiding Officer
Assigned Commissioner

**(END OF ATTACHMENT F.)**

R.00-10-002
D.01-04-006

Commissioner Henry M. Duque, concurring:

There is no dispute that the programs are essential for our energy survival this summer. The programs will generate a positive demand response to the negative supply situation we are facing in the coming months. It is therefore critical that these programs succeed.

The final version of Item 6 contains many thoughtful programmatic changes in response to comments. Yet it does not contain a current funding mechanism for the programs. Because of their importance to the State of California, there should be immediate funding, through a surcharge, so that the utilities can implement these vital load curtailment programs.

There is also no dispute that the utilities will incur costs to implement the new load curtailment programs. Through a lack of immediacy, Item 6 fails to acknowledge that the utilities must have some *current* funding sources to pay for the programs. My alternate decision, Item 6a, would have provided a means for the utilities to pay for these programs and give customers more information about the kinds of energy procurement options available. Perhaps, customers would rather pay themselves by forming interruptible circuit groups. I think customers would be more likely to participate in these programs if they were able to see the contribution this effort makes in a separately identified surcharge. My alternate decision did not prevail, however.

For these reasons, I remain concerned over the creditworthiness of the utilities. Without other default provider options, it is necessary to restore the utilities financial health, so that they can provide safe and reliable electric service. The interruptible program costs adopted today will be added to the already-huge undercollections. For SDG&E alone, the program costs are estimated to be one-half a billion dollars annually. While we may not agree with their estimate, the fact is that the programs costs will now be added to SDG&E's more than $447 million undercollection.

As for PG&E, it is reporting to its bondholders that it expects to take a $4.1 billion after-tax charge for the past undercollected costs. And, PG&E is also reporting that, if it were current in payments to creditors, its cash balance would be a negative $1.8 billion. On top of that, we just ordered the utilities to pay their QF and DWR bills. For PG&E, this equates to a $1.5 billion obligation that is due between now and April 30th. My read of Edison's March 20th 8K filing paints an equally bleak picture.

So, is there enough money within the 3 cent surcharge we adopted on March 27th to pay for all these energy and energy management programs? As I asked in the rate increase vote, is 3 cents enough? I still don't know. The record here yields no answer. I do know there is no mechanism for the utilities to recover their mounting costs. The financial situation of the utilities can only worsen, and the programs may not come to fruition.

/s/ HENRY M. DUQUE
Henry M. Duque
Commissioner

April 3, 2001

San Francisco